Chapter 55 Oil and Gas Properties Production Tax

Section

9660. (Repealed).

9670. (Repealed).

9690. (Repealed).

9694. (Repealed).

9699. (Repealed).

9700. (Repealed).

15 AAC 55.010. Monthly production rate at the economic limit for oil or gas produced before 1/1/95

(a) The presumed monthly production rate at the economic limit of 300 barrels per well day for oil production of a lease or property includes royalty and all other ownership interests in that production.

(b) When the monthly production rate at the economic limit is being determined for a lease or property by dividing the per-unit value of production into the average monthly direct operating costs, the monthly production rate at the economic limit equals the final quotient obtained by dividing, first, the per-unit value of production into the average monthly direct operating costs other than royalty, and then dividing the first quotient by the fraction of production corresponding to all nonroyalty interests in the lease or property. If some or all of a direct operating cost is borne by a royalty interest, then with respect to that cost the royalty interest will be regarded as a nonroyalty interest, for purposes of the preceding sentence.

(c) The tax on oil produced from a lease or property in commercial production after June 30, 1981, must be computed by using the rates specified in AS 43.55.011 (b) and the economic limit factor specified in AS 43.55.013 (b). "Commercial production," for purposes of this subsection, means the production of oil for purposes of sale, or other beneficial use not associated with the exploration and development of the field in which the lease or property lies, except when the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval.

(d) When the primary production from a well or wells on a lease or property is gas, the monthly production at the economic limit for that lease or property is presumed to be 3,000 Mcf per well times the number of well days for that lease or property during that month for which the tax is to be paid. The economic limit for gas production of a lease or property includes royalty and all other ownership interests in the production. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence that the value determined under AS 43.55.013 (i) for the lease or property, when divided into the average monthly direct operating cost determined under AS 43.55.013 (h) for the lease or property, produces a different amount for the monthly production at the economic limit under AS 43.55.013 (g) for the lease or property.

(e) This section applies only to oil or gas produced before 1/1/95.

History: Eff. 7/1/77, Register 63; am 3/26/82, Register 81; am 1/1/95, Register 132

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.013

AS 43.55.110

15 AAC 55.011. Determination of applicable tax rate for oil and monthly production rate at the economic limit for oil or gas produced on or after 1/1/95

(a) The monthly production rate at the economic limit of 300 barrels per well day for oil production of a lease or property includes royalty and all other ownership interests in that production.

(b) For purposes of AS 43.55.011 (b), the first five years after the start of commercial oil production elapse when 43,830 total hours of commercial oil production from the lease or property have accumulated. "Commercial oil production" means oil production that either changes ownership or is removed from the lease or property. A producer shall keep a record of each hour in which there is any commercial oil production from a lease or property until 43,830 total hours of commercial oil production from the lease or property have accumulated.

(c) If a tax rate changes on or before the last day of a monthly reporting period due to the elapsing of the first five years after the start of commercial oil production, the department will apply the new tax rate only to that portion of production for the month that equals the number of days in the month that include and follow the day on which the five years elapsed, divided by the total number of days in that month.

(d) When the monthly production rate at the economic limit is being determined for gas produced from a lease or property by dividing the per-unit value of production into the average monthly direct operating costs, the monthly production rate at the economic limit equals the final quotient obtained by dividing, first, the per-unit value of production into the average monthly direct operating costs other than royalty, and then dividing the first quotient by the fraction of production corresponding to all nonroyalty interests in the lease or property. If some or all of a direct operating cost is borne by a royalty interest, then the royalty interest bearing that cost will be regarded as a nonroyalty interest, for purposes of the preceding sentence.

(e) The monthly production rate at the economic limit for gas production of a lease or property includes royalty and all other ownership interests in the production. The taxpayer may rebut the presumed monthly production rate at the economic limit of 3,000 Mcf per well day at a formal hearing under AS 43.05.240 by providing clear and convincing evidence that the value determined under AS 43.55.013 (i) for the lease or property, when divided into the average monthly direct operating cost determined under AS 43.55.013 (h) for the lease or property, produces a different amount for the monthly production rate at the economic limit under AS 43.55.013 (g) for the lease or property.

(f) The provisions of (b) of this section apply to a lease or property for which commercial oil production as defined in 15 AAC 55.010(c) did not start before five years before 1/1/95. Except as provided in the preceding sentence, this section applies only to oil or gas produced on or after 1/1/95.

History: Eff. 1/1/95, Register 132

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.013

AS 43.55.110

15 AAC 55.020. Well days for oil or gas produced before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 2/23/88, Register 105; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.021. Well days and calculation of economic limit factor for oil or gas

(a) A producer that is also the operator of a lease or property shall, as part of the return filed under AS 43.55.030 , submit a detailed account of the individual well data showing the number of days and fractions of days that a well operated for the month for which the tax is being paid. A producer that is not the operator shall, as part of the return filed under AS 43.55.030 , either submit that account or acknowledge in the designated section of the return that the producer is relying on the well days that the operator of the lease or property reported.

(b) The number of well days during a month for a well is the number of hours that the well is operating during the month, divided by 24. The producer shall calculate both hours and well days to the first decimal place using the automatic convention in the rounding command or function in commercially available software.

(c) A well is operating for purposes of this section when the well is yielding oil or gas that is considered to be produced under AS 43.55 and this chapter. An injection well, or a well yielding only gas that is not considered to be produced under 15 AAC 55.071 and 15 AAC 55.151(e) , is not operating within the meaning of this section.

(d) For purposes of calculating the economic limit factor for oil, a producer shall include the production of all oil, as "oil" is defined under AS 43.55.900 . For purposes of calculating the economic limit factor for gas, a producer shall include the production of all gas, as "gas" is defined under AS 43.55.900 .

(e) If both oil and gas are produced from a lease or property in the month for which the tax is to be paid, the producer shall allocate the total well days for the lease or property between the oil and gas based on the relative volumes of oil and gas produced from the lease or property for the month. For purposes of that allocation, one barrel of oil is equivalent to 10 Mcf of gas. For a month in which both oil and gas are produced from a lease or property, a producer that is also the operator of the lease or property shall provide, as part of the return filed under AS 43.55.030 , supporting information on its calculation of the relative volumes of oil and gas for purposes of allocation under this subsection. A producer that is not the operator shall, as part of the return filed under AS 43.55.030 , either submit the supporting information described in this subsection or acknowledge in the designated section of the return that the producer is relying on the supporting information that the operator of the lease or property reported.

(f) A hole drilled or bored in the ground to produce oil or gas, or both, is a single well, regardless of how many completions or lateral extensions that hole contains; how many pools, formations, or zones are produced through that hole; or whether that hole produces both oil and gas. A producer may not count a given hour of a single well's operation more than once in calculating one or more economic limit factors, regardless of how many of the well's completions or lateral extensions may have produced during that hour; how many pools, formations, or zones may have been produced through the well during that hour; or whether the well produced both oil and gas during that hour.

(g) If a single well produces oil or gas during a month from two or more separate leases or properties that have not been aggregated under AS 43.55.013 (j), the producer shall allocate the hours of operation of that well between the separate leases or properties when calculating the respective well days for the separate leases or properties for the month for which the tax is to be paid. If the well produces only oil during the month, the producer shall allocate the hours of operation during the month based on the relative volumes of oil that the well produced from the separate leases or properties during the month. If the well produces only gas during the month, the producer shall allocate the hours of operation during the month based on the relative volumes of gas that the well produced from the separate leases or properties during the month. If the well produces both oil and gas during the month, the producer shall allocate the hours of operation during the month based on the relative volumes of oil and gas that the well produced from the separate leases or properties during the month. For purposes of that allocation, one barrel of oil is equivalent to 10 Mcf of gas. For a month in which both oil and gas are produced from a lease or property, the producer that is also the operator of the lease or property shall provide, as part of its return under AS 43.55.030 , supporting information on its calculation of the relative volumes of oil and gas for purposes of allocation under this subsection. A producer that is not the operator shall, as part of the return filed under AS 43.55.030 , either submit the supporting information described in this subsection or acknowledge in the designated section of the return that the producer is relying on the supporting information that the operator of the lease or property reported.

(h) For purposes of this section, "gas produced" or "gas production" includes only gas considered to be produced under 15 AAC 55.071 and 15 AAC 55.151(e) .

(i) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160

Authority: AS 43.05.080

AS 43.55.013

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.900

15 AAC 55.025. Computation of economic limit factor after 10 years of production for oil produced before January 1, 1989

Repealed.

History: Eff. 6/30/87, Register 103; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.027. Use of common production facilities between leases or properties

(a) For purposes of determining economic limit factors under AS 43.55.013 and their application to AS 43.55.011 or 43.55.016, the department will, in its discretion, under AS 43.55.013 (j), aggregate two or more leases or properties, or portions of them, or segregate a lease or property into two or more parts at any time, whether before or after the start of commercial production or upon departmental audit of a producer, except that the department will not aggregate leases or properties subject to an advance ruling under this section for the periods to which the advance ruling applies.

(b) Upon application of a producer that proposes use of common production facilities to produce oil or gas from two or more leases or properties, the department will, in its discretion, issue an advance ruling that the department will not aggregate specified leases or properties for purposes of determining economic limit factors under AS 43.55.013 , if the department determines that

(1) the use of the common production facilities will substantially reduce the cost of oil or gas production;

(2) the advance ruling will enhance the likelihood of developing a new pool;

(3) oil and gas produced through the common production facilities will be accurately allocated to the respective leases or properties covered by the advance ruling; and

(4) production operations on the respective leases or properties would not be economically interdependent in the absence of the proposed use of common production facilities.

(c) If an advance ruling is issued under (b) of this section, the department will specify whether that ruling applies only to oil production, only to gas production, or to production of both oil and gas from those leases or properties.

(d) A producer shall submit with the application for an advance ruling under (b) of this section a list of all producers affected by the advance ruling and any information requested by the department to support a departmental determination on the application. Additionally, the producer shall submit any additional information requested by the department at a later time that is necessary to make the determination on the application.

(e) If requested by the department, the applicant shall give notice to all producers to be affected by the advance ruling. The notice must describe the nature of and reasons for the application for an advance ruling. An affected producer receiving notice of the application for an advance ruling may, within 15 days after the date of receiving the notice, provide written comments to the department on the application for the advance ruling.

(f) The department will, in its discretion, issue an advance ruling under (b) of this section subject to terms and conditions as set out in the advance ruling. For purposes of determining amounts of gas considered not produced under 15 AAC 55.151(e) (1), an advance ruling will allocate gas used in common production facility operations to each lease or property covered by that ruling.

(g) If the department finds a material noncompliance with the terms and conditions set out in an advance ruling under this section, the department will, in its discretion, revoke the ruling or issue an order that the continued effectiveness of the ruling be conditioned on the affected producers' performance of specified action to cure the noncompliance. The department will provide notice of that proposed revocation or other order to the producer that received the advance ruling and other affected producers that the applicant specified under (d) of this section. This notice will specify the effective date of the proposed revocation, which will be the date, as determined by the department, that the material noncompliance began, unless the department finds good cause to select a later date; or the date by which the curative action must be completed. An affected producer may, within 15 days after the department issues the notice, make a written request for an informal meeting with the department and other affected producers to discuss the proposed revocation or other order. The producer requesting the meeting shall notify other affected producers of its request. In the absence of a timely request, upon the expiration of 15 days after the department issues notice a proposed revocation will become effective as of the date specified in the notice, or the continued effectiveness of the advance ruling will be conditioned on completion of the specified curative action by the date specified in the notice. After an advance ruling has been revoked or expires under this subsection, the department will, in its discretion, aggregate affected leases or properties under AS 43.55.013 (j) as of a date on or after the effective date of the revocation or expiration.

(h) When appropriate to address a change in leases or properties to be covered by an advance ruling, ownership interests, allocation method, production operations, composition of produced fluids, or other relevant circumstances, or when otherwise appropriate to ensure that the criteria set out in (b) of this section will be met, the department will, in its discretion, on request of a producer or on its own motion, modify an advance ruling under this section. The department will provide notice of a proposed modification to the affected producers that the applicant specified under (d) of this section. This notice will describe the nature of the modification being considered, the reasons for and purpose of the modification, and the expected effects and results of the modification, and will specify the effective date of the modification, which will be the date the notice is issued, unless the department finds good cause to select another date. An affected producer may, within 15 days after the department issues the notice, make a written request for an informal meeting with the department and other affected producers to discuss the proposed modification. That affected producer also shall notify other affected producers of its request. In the absence of a timely request, upon the expiration of 15 days after the department issues notice the proposed modification will become effective as of the date specified in the notice.

(i) A producer aggrieved by the department's action revoking an advance ruling, ordering that the continued effectiveness of the ruling be conditioned on the affected producers' performance of specified action to cure the noncompliance, or modifying an advance ruling may appeal that action under 15 AAC 05.001 - 15 AAC 05.050. During the pendency of an appeal, a producer affected by the department's action shall report and pay taxes in compliance with the department's action. If the department's action is modified or reversed as a result of the appeal, the producer shall amend its returns and pay tax for all tax periods to which the determination on appeal applies.

(j) The department's denial of an application for an advance ruling or the department's failure to issue an advance ruling does not affect the department's authority to act under AS 43.55.013 (j).

(k) If an agreement by the department not to aggregate leases or properties that are using common production facilities to produce oil or gas is in effect on 1/1/95, the agreement expires 90 days after 1/1/95, except that if a producer that is a party to the agreement applies on or before 90 days after 1/1/95 for an advance ruling covering the leases or properties subject to the agreement, the agreement expires on the date that the department acts on the producer's application. Nothing in this section or in the fact that the department previously agreed not to aggregate the leases or properties bars or otherwise limits the department, in acting on an application for an advance ruling under this subsection, from imposing terms and conditions different from those in the previous agreement.

History: Eff. 1/1/95, Register 132

Authority: AS 43.05.040

AS 43.05.080

AS 43.55.011

AS 43.55.013

AS 43.55.016

AS 43.55.020

AS 43.55.040

AS 43.55.110

15 AAC 55.030. Economic limit factor for casinghead gas produced before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 3/26/82, Register 81; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.040. Interim taxation of gas well gas

Repealed.

History: Eff. 7/1/77, Register 63; repealed 1/1/95, Register 132

15 AAC 55.045. Economic limit factor for distillate or condensate produced before 1/1/95

Repealed.

History: Eff. 3/26/82, Register 81; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.050. Gas run through a gas processing plant

For gas that has been run through a gas processing plant, the comparison of the cents-per-Mcf amount under AS 43.55.016 (c) and the percentage-of-value amount under AS 43.55.016 (b) may not be made by comparing cents-per-Mcf to percentage-of-value for the residue gas separately from the extracted liquids. The percentage-of-value amount is to be based on the full consideration received by the producer for that gas in an arm's length transaction, or, in the absence of an arm's length transaction, the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant, as set out in 15 AAC 55.052 if applicable. The cents-per-Mcf amount is to be based on the volume of gas delivered to the gas processing plant, minus the sum of

(1) the volume of residue gas used in the operation of a lease or property in drilling for or producing oil or gas;

(2) the volume of residue gas injected into a reservoir for repressuring; and

(3) that portion of the residue gas used as fuel in the processing plant, calculated by multiplying the total volume of residue gas used as fuel in the processing plant times the ratio of the sum of the volume, in Mcf equivalent, of non-taxable NGLs and the volume of non-taxable residue gas to the sum of the volume, in Mcf equivalent, of both taxable and non-taxable NGLs and the volume of both taxable and non-taxable residue gas other than residue gas used as fuel in the plant.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.016

AS 43.55.110

AS 43.55.900

15 AAC 55.052. Reasonable allowance for processing gas in a gas processing plant and for transporting gas from its point of production to a gas processing plant

Under AS 43.55.900 (7)(B) and (C), the reasonable allowance for processing gas at a gas processing plant that is located in the state and that has a yearly average throughput of more than one billion cubic feet of gas per day, and for transporting the gas from its point of production to that gas processing plant is $.85 per barrel for taxable NGLs and $.20 per Mcf for taxable residue gas. The cost of gas used as fuel in the gas processing plant to extract or process taxable NGLs and residue gas, including production tax payable on that gas used as fuel, is included in this allowance. This allowance is net of the liability for production tax on that gas used as fuel. A production tax need not be separately paid on that gas used as fuel except when the cents-per-Mcf amount applies under AS 43.55.016 and 15 AAC 55.050.

History: Eff. 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.016

AS 43.55.110

AS 43.55.900

15 AAC 55.060. Lease identification number

The department will, in its discretion, require the person paying the tax to include an identification number on the statement filed.

History: Eff. 1/2/71, Register 36; am 1/1/95, Register 132

Authority: AS 43.55.030

AS 43.55.080

AS 43.55.110

15 AAC 55.070. Penalty for gas flared before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.071. Gas flared

(a) Gas flared in excess of that needed for safety purposes, except gas used in the operation of a lease or property, is taxed at the rate provided by AS 43.55.016 .

(b) For purposes of this section and AS 43.55.020 (e), gas is needed for safety purposes if the Alaska Oil and Gas Conservation Commission authorizes gas to be flared or vented for one of the following reasons:

(1) as the result of an emergency or operational upset for a period not exceeding one hour;

(2) as pilot and purge gas to test or fuel the safety flare system; or

(3) if an emergency that threatens life or property requires flaring or venting for a period exceeding one hour.

(c) For purposes of this section and AS 43.55.020 (e), flaring or venting of gas is a use of the gas in the operation of a lease or property if the Alaska Oil and Gas Conservation Commission does not classify the flaring or venting as waste and if

(1) the gas is flared or vented as the result of a planned lease operation for a period not exceeding one hour and in a volume not exceeding 5,000 Mcf, unless the flaring or venting is part of a longer operation that is interrupted in order to evade the one hour limitation; or

(2) a part of the operation of the lease or property could not be carried out without the use of the gas or a substitute. Under this paragraph, flaring or venting for the purpose of disposal does not constitute use of gas in the operation of a lease or property.

(d) For purposes of AS 43.55.020 (e), gas is flared beyond the amount authorized for safety by the Alaska Oil and Gas Conservation Commission under AS 31.05 if the Alaska Oil and Gas Conservation Commission does not authorize the gas to be flared or vented or if it classifies the flaring as waste. Such gas is taxed at the rate provided by AS 43.55.016 and in addition is subject to a penalty under AS 43.55.020 (e) equal to the tax.

(e) For purposes of (a) and (d) of this section, the gross value at the point of production of the flared gas must be determined using the prevailing value under 15 AAC 55.173.

(f) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.016

AS 43.55.020

AS 43.55.110

15 AAC 55.080. Interest

If it is determined for any reason that returns made and taxes paid for production during a month were incorrect and a greater tax was due for the production, interest on the amount of the additional tax due for that production is calculated and collected at the rate provided by AS 43.05.225 for the time beginning with and including the first day of the month after the month in which the tax is due, and to and including the day the additional tax for that production is paid.

History: Eff. 7/1/77, Register 63; am 1/1/95, Register 132; am 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.05.225

AS 43.55.060

AS 43.55.110

15 AAC 55.090. Significant digits in economic limit factors

All economic limit factors are to be calculated to six decimal places using the automatic convention in the rounding command or function in commercially available software.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 1/1/2002, Register 160

Authority: AS 43.05.080

AS 43.55.013

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.100. Average API gravity

The API gravity of oil produced from a lease or property will be calculated each month using the weighted average of the API gravities of the oil produced during that month from the lease or property.

History: Eff. 3/7/74, Register 49; am 6/28/74, Register 50; am 7/1/77, Register 63

Authority: AS 43.05.080

AS 43.55.012

AS 43.55.110

15 AAC 55.110. Application of early development incentive credit against production tax

Repealed.

History: Eff. 12/24/75, Register 56; repealed 1/1/95, Register 132

15 AAC 55.115. Accounting for shrinkage when oil and NGLs are commingled

(a) In determining a producer's tax liability under AS 43.55 and this chapter, if the quantity of oil produced from a lease or property is calculated from a volumetric measurement of commingled oil and NGLs rather than directly metered, the producer shall account for the effect of volumetric shrinkage on the producer's volumes of oil and NGLs due to blending of the NGLs with the oil by

(1) calculating the volumetric shrinkage percentage using the equation in customary units that is set out in section 5.3 of the American Petroleum Institute *Manual of Petroleum Measurement Standards,* Chapter 12 *(Calculation of Petroleum Quantities),* Section 3 *(Volumetric Shrinkage Resulting from Blending Light Hydrocarbons with Crude Oils),* 1st edition, July 1996; as described in this paragraph, section 5.3 is adopted by reference;

(2) calculating the total shrinkage-adjusted volume of commingled oil produced from the lease or property during the month by solving the following equation for QOIL:

QOIL = MVBLEND / (1 - S) - MVNGL

where

QOIL = the total shrinkage-adjusted volume of oil produced from the lease or property during the month by all producers and commingled with NGLs;

MVBLEND = the total metered volume of commingled oil and NGLs produced from the lease or property during the month by all producers;

S = the volumetric shrinkage percentage calculated under (1) of this subsection; and

MVNGL = the total pre-commingling metered volume of NGLs produced from the lease or property during the month by all producers and commingled with oil;

(3) calculating the total shrinkage-adjusted volume of NGLs produced from the lease or property during the month by subtracting QOIL from MVBLEND;

(4) calculating the total shrinkage amount by subtracting the shrinkage-adjusted volume of NGLs under (3) of this subsection from MVNGL;

(5) calculating the producer's share of the total shrinkage amount by multiplying the total shrinkage amount under (4) of this subsection by the ratio of the producer's pre-commingling metered volume of NGLs from the lease or property during the month to MVNGL;

(6) calculating the producer's quantity of commingled NGLs for production tax purposes by subtracting the producer's share of the total shrinkage amount under (5) of this subsection from the producer's pre-commingling metered volume of NGLs from the lease or property during the month; and

(7) calculating the producer's quantity of commingled oil for production tax purposes by subtracting the quantity of NGLs under (6) of this subsection from the producer's metered volume of commingled oil and NGLs from the lease or property during the month.

(b) In accounting for the effect of volumetric shrinkage percentage under (a) of this section, a producer

(1) shall express all metered volumes and all specific gravities and API gravities as adjusted to 60 degrees Fahrenheit and approximately 15 pounds per square inch absolute;

(2) shall estimate the concentration in liquid volume percent of lighter component in commingled oil and NGLs by dividing the pre-commingling metered volume of NGLs by the metered volume of the commingled oil and NGLs;

(3) if the measured pre-commingling API gravity of the commingled oil is unavailable, shall calculate the API gravity of that oil from the specific gravities of the pre-commingling NGLs and of the commingled oil and NGLs, treating the specific gravity of the commingled oil and NGLs as the volume-weighted average of the specific gravities

of the oil and of the NGLs and using the following equations to convert between API gravity and specific gravity:

API = 141.5/SG-131.5

SG = 141.5/(API + 131.5)

where

API = the API gravity; and

SG = the specific gravity.

(c) In determining economic limit factors under AS 43.55.013 and 15 AAC 55.021, if (a) of this section applies, a producer shall account for the effect of volumetric shrinkage due to commingling of NGLs with oil by using Q_{OIL} under (a)(2) of this section as the volume of commingled oil produced from the lease or property and by using the total shrinkage-adjusted volume of NGLs under (a)(3) of this section, converted from barrels to Mcf equivalents, as the volume of gas in the form of commingled NGLs produced from the lease or property.

(d) The following example illustrates (a) and (b) of this section:

Step One: Estimate concentration in liquid volume percent of lighter component ("C") under (b)(2) of this section.

Input 1: Known volumes

(number of barrels)

Metered NGLs 126,839 = MV_{NGL}

Blended Stream 1,267,000 = MV_{BLEND}

Calculation 1: Concentration of NGLs in mixed stream

(ratio of the two inputs from Input 1)

C = 126,839 / 1,267,000 = .100 = 10.0%

Step Two: Estimate the API gravity difference ("G") under (b)(3) of this section.

Input 2: Known gravities

(degrees API)

Blended Stream 34.0

Metered NGLs 90.0

Calculation 2A: Convert the API gravities into specific gravities.

Blended Stream SG_{BLEND} = 141.5/(API+131.5)

= 141.5/(34.0+131.5) = 0.855

Metered NGLs SG_{NGL} = 141.5/(API+131.5)

= 141.5/(90.0+131.5) = 0.639

Calculation 2B: Back calculate the estimated specific gravity of the oil stream.

Calculation 2Bi: Estimate Oil Volume.

MV_{BLEND} - MV_{NGL} = Oil Volume

= 1,267,000 - 126,839 = 1,140,161

Calculation 2Bii: Obtain the products of multiplying the specific gravities from Calculation 2A by the respective volume for each stream from Step One.

MV_{BLEND} * SG_{BLEND} = $PRODUCT_{BLEND}$

= 1,267,000 * 0.855 = 1,083,285

MV_{NGL} * SG_{NGL} = $PRODUCT_{NGL}$

= 126,839 * 0.639 = 81,050

Calculation 2Biii: Estimate the implied product for oil.

$PRODUCT_{BLEND}$ - $PRODUCT_{NGL}$ = $PRODUCT_{OIL}$

= 1,083,285 - 81,050

= 1,002,235

Calculation 2Biv: Calculate the estimated specific gravity for the oil stream.

$PRODUCT_{OIL}$ / OIL VOLUME = $SG_{OIL\ STREAM}$

= 1,002,235 / 1,140,161 =.879

Calculation 2C: Convert oil specific gravity into API gravity.

Oil API=141.5/SG - 131.5=141.5/.879 - 131.5 = 29.5

Calculation 3: Calculate "G," where "G" equals the difference between known NGL API gravity and calculated oil API gravity from Calculation 2C.

G = 90.0ø - 29.5ø = 60.5ø

Step Three: Calculate volumetric shrinkage percentage ("S") under (a)(1) of this section.

$S = 4.86 * 10^{-8} * C * (100-C)^{.819} * G^{2.28}$

$= 4.86 * 10^{-8} * 10.0 * (100-10.0)^{.819} * 60.5^{2.28}$

= 0.2236 percent, or 0.002236

Step Four: Calculate the shrinkage-adjusted oil volume, Q<u>OIL</u>, under (a)(2) of this section using the result from Step Three.

Q<u>OIL</u> = MV<u>BLEND</u> / (1 - S) - MV<u>NGL</u>

= 1,267,000 / (1 - 0.002236) - 126,839 = 1,143,000

<u>**Step Five: Calculate the shrinkage-adjusted NGL volume under (a)(3) of this section using the result from Step Four.**</u>

Shrinkage-adjusted NGL Volume = MV<u>BLEND</u> - Q<u>OIL</u>

= 1,267,000 - 1,143,000

= 124,000

<u>**Step Six: Calculate the total shrinkage amount under (a)(4) of this section using the result from Step Five.**</u>

Total Shrinkage Amount = MV<u>NGL</u> - Shrinkage-adjusted NGL

Volume

= 126,839 - 124,000 = 2,839

<u>**Producer A:**</u>

<u>**Step Seven A: Calculate the producer's share of the total shrinkage amount under (a)(5) of this section using the result of Step Six.**</u>

<u>**Input 3a:**</u>

Producer's Metered NGL Volume 92,061

Total Metered NGL Volume (MV<u>NGL</u>) 126,839

Producer's Share of Total Shrinkage Amount = Total Shrinkage Amount * Producer's Metered NGL Volume/MV<u>NGL</u>

= 2,839 * 92,061 / 126,839 = 2,061

<u>**Step Eight A: Calculate the producer's NGL quantity under (a)(6) of this section using the result of Step Seven A.**</u>

Producer's NGL Quantity = Producer's Metered NGL Volume

- Producer's Share of

Total Shrinkage Amount

= 92,061 - 2,061 = 90,000

<u>**Step Nine A: Calculate the producer's oil quantity under (a)(7) of this section using the result of Step Eight A.**</u>

<u>**Input 4a:**</u>

Producer's Metered Commingled Volume 657,000

Producer's Oil Quantity = Producer's Metered Commingled

Volume - Producer's NGL Quantity

= 657,000 - 90,000 = 567,000

Producer B:

Step Seven B: Calculate the producer's share of the total shrinkage amount under (a)(5) of this section using the result of Step Six.

Input 3b:

Producer's Metered NGL Volume 34,778

Total Metered NGL Volume (MVNGL) 126,839

Producer's Share of Total Shrinkage Amount = Total Shrinkage

Amount * Producer's Metered NGL Volume/MVNGL

= 2,839 * 34,778 / 126,839 = 778

Step Eight B: Calculate the producer's NGL quantity under (a)(6) of this section using the result of Step Seven B.

Producer's NGL Quantity = Producer's Metered NGL Volume

- Producer's Share of Total

Shrinkage Amount

= 34,778 - 778 = 34,000

Step Nine B: Calculate the producer's Oil Quantity under (a)(7) of this section using the result of Step Eight B.

Input 4b:

Producer's Metered Commingled Volume 610,000

Producer's Oil Quantity = Producer's Metered Commingled

Volume - Producer's

NGL Quantity

= 610,000 - 34,000 = 576,000

History: Eff. 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.013

AS 43.55.016

AS 43.55.110

AS 43.55.900

Editor's note: The American Petroleum Institute *Manual of Petroleum Measurement Standards,* Chapter 12, Section 3, may be reviewed during business hours at the Alaska Department of Revenue, Oil and Gas Audit Division, 550 W. 7*th* Avenue, Suite 500, Anchorage, AK 99501 and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street N.W., Washington, D.C. 20005-4070.

15 AAC 55.120. Payment and reporting procedures

Repealed 9/15/82.

15 AAC 55.122. Supplemental submissions

(a) Within 60 days after 1/1/2000, a producer that is subject to tax under AS 43.55 shall provide to the department a complete copy of all contracts, agreements, and amendments to all contracts and agreements that are in effect on 1/1/2000 and that concern the sale, exchange, or transportation of oil or gas produced in the state.

(b) With the filing of the monthly tax return under AS 43.55, a producer shall provide to the department, as part of the producer's statement or report, a complete copy of each contract, agreement, or amendment to a contract or agreement that was entered into during the month to which the tax return applies, and that concerns the sale, exchange, or transportation of oil or gas produced in the state, unless the contract, agreement, or amendment to the contract or agreement was previously provided to the department under this section. The producer shall also provide to the department a summary list of all contracts, agreements, or amendments to contracts or agreements that concern the sale, exchange, or transportation of oil or gas produced in the state during the month to which the tax return applies. The list must include a notation as to when each contract was provided to the department. On the tax return prescribed by the department, a producer shall identify the contract, agreement, or amendment to the contract or agreement that concerns each disposition of oil or gas reported on that return.

(c) No later than 60 days after the department sends a written request, a producer shall provide to the department a copy of any additional documents concerning a matter that is the subject of a submission provided to the department under (a) or (b) of this section.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.150. Valuation of oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.151. Valuation of oil or gas

(a) Except as otherwise provided in 15 AAC 55.050 or 15 AAC 55.163, this section applies to all oil and gas produced in the state on a lease or property, regardless of whether the oil or gas is removed from the lease or property, less any oil or gas the ownership of or right to which is exempt from state taxation.

(b) The gross value at the point of production for a producer's oil or gas must be calculated as follows:

(1) a destination value must be determined for the oil or gas or, if oil and NGLs are commingled before being tendered to a common carrier or before being transported from the lease or property, for the commingled oil and NGLs; the destination value is the sales price under 15 AAC 55.161 unless (c) or (d) of this section applies, in which case the destination value is the prevailing value under 15 AAC 55.171 or 15 AAC 55.173, as applicable;

(2) except as otherwise provided under (i) of this section, the producer's reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.191 must be subtracted from the destination value determined under (1) of this subsection; reasonable costs of transportation are calculated

(A) for oil or gas other than gas that has been run through a gas processing plant, from the point of production of the oil or gas to its sales delivery point or, if different, to the point where prevailing value is calculated under 15 AAC 55.171 or 15 AAC 55.173;

(B) for gas that has been run through a gas processing plant, from the plant to the sales delivery point or, if different, to the point where prevailing value is calculated under 15 AAC 55.171 or 15 AAC 55.173;

(3) if oils of different qualities or oil and NGLs are commingled, the value calculated under (2) of this subsection must be adjusted for any consideration paid or received for quality differentials, regardless of whether prescribed by a filed tariff;

(4) if gas has been run through a gas processing plant, a reasonable allowance under AS 43.55.900 (7)(B) or (C) and, as applicable, 15 AAC 55.052, must be subtracted from the sum of

(A) the value calculated under (2) of this subsection for the residue gas from the plant;

(B) the value calculated under (2) of this subsection, as adjusted under (3) of this subsection, for the NGLs extracted at the plant other than NGLs that are commingled with oil before being tendered to a common carrier or before being transported from the lease or property; and

(C) the value calculated under (i) of this section for the NGLs extracted at the plant that are commingled with oil before being tendered to a common carrier or before being transported from the lease or property.

(c) The prevailing value under 15 AAC 55.171 or 15 AAC 55.173 must be used in determining the gross value at the point of production for a producer's oil or gas if

(1) the producer's oil or gas is refined, used as fuel or petrochemical feedstock, or otherwise consumed at a refinery or plant owned by the producer, or the oil or gas is transferred from the producer in other than an arm's-length, third party transaction;

(2) the prevailing value for the producer's gas under 15 AAC 55.173, other than NGLs commingled with oil, exceeds the sales price for that gas under 15 AAC 55.161; or

(3) the prevailing value for the producer's oil, or commingled oil and NGLs, under 15 AAC 55.171, plus the actual costs incurred to transport the oil or commingled oil and NGLs from the point where prevailing value is calculated to the sales delivery point, exceeds the sales price under 15 AAC 55.161 by more than $.15 per barrel.

(d) The department will, in its discretion, apply prevailing value if the circumstances relating to the disposition of the producer's oil or gas show fraud or an intent to evade taxes.

(e) For purposes of AS 43.55 and this chapter, production of gas does not include gas

(1) used or unavoidably lost in production operations on a lease or property in the state by the producer;

(2) flared in amounts needed for safety purposes;

(3) injected by the producer into a reservoir on a lease or property in the state in the course of operations for purposes of repressuring or conservation, including enhanced recovery;

(4) on which production tax has been previously paid;

(5) vented in de minimis amounts incidental to normal oil field operations as authorized by the Alaska Oil and Gas Conservation Commission; or

(6) sold or otherwise transferred by the producer to another producer of oil or gas in the state for use in a manner described in (1) or (3) of this subsection, if

(A) the producer of the gas

(i) obtains an affidavit from the purchaser or transferee certifying under penalty of perjury that the gas was used in the past year for a purpose described in (1) or (3) of this subsection; and

(ii) once each year between January and March attaches the affidavit obtained under (i) of this subparagraph to the producer's monthly production tax return filed with the department; and

(B) the gas is actually used in a manner described in (1) or (3) of this subsection.

(f) Gas deemed not to be produced under (e)(3) or (e)(6) of this section is subject to tax on the basis of prevailing conditions, including the economic limit factor, at the time, and for the lease or property from which, the gas is ultimately produced.

(g) If a producer transfers oil, or commingled oil and NGLs, to a third party for purposes of operational necessity or convenience in what otherwise would be a bona fide, arm's-length exchange but for the fact that at the time of the particular transfer the producer expects to receive a like amount of similar quality oil, or commingled oil and NGLs, produced in the state from that third party, the transfer to a third party and the transfer from the third party are disregarded and the oil, or commingled oil and NGLs, is treated as if it had remained in the possession of the original transferring producer until final disposition of that oil, or commingled oil and NGLs. If the transfers under that exchange are made at different locations, the location differential paid by a producer is treated as a transportation cost and the location differential received by a producer is treated as a reimbursement of a transportation cost.

(h) Repealed 1/1/2000.

(i) If oil and NGLs are commingled before being tendered to a common carrier or before being transported from the lease or property, the costs of transportation under (b)(2) of this section must be calculated separately for transportation upstream and transportation downstream of the point where the oil and NGLs are commingled or the point of production for the oil, whichever point is farther downstream. The downstream portion of the costs of transportation calculated under this subsection must be subtracted from the destination value of the commingled oil and NGLs, and the remainder under this calculation must be adjusted for the quality differentials described under (b)(3) of this section. The resulting value is the "commingled-oil-and-NGLs netback value" and must be allocated between the oil and NGLs in accordance with 15 AAC 55.175. The applicable upstream portions of the costs of transportation, if any, calculated under this subsection must be subtracted from the respective values calculated for the oil (V_{OIL}) and NGLs (V_{NGL}) under 15 AAC 55.175.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

AS 43.55.900

15 AAC 55.160. Sales price for oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.161. Sales price for oil or gas

(a) For purposes of this chapter, the sales price for oil or gas is the cash value of the full consideration being given in receipt for oil or gas transferred from a producer in an arm's-length, third party transaction.

(b) Repealed 1/1/2000.

(c) In an exchange, the cash value for purposes of (a) of this section of the crude received in the exchange is

(1) the average spot price of the crude received that is published during the month that corresponds most closely to the pricing period identified in the contract for the crude received, if the crude received is priced by reference to a crude other than ANS and a pricing period is identified in the contract; or

(2) the average spot price of the crude received that is published during the month of delivery of the crude received, if the crude received is priced by reference to ANS or if a pricing period is not identified in the contract.

(d) If oil or gas is sold under a contract that contains a provision for reimbursing the producer for all or any part of the production taxes paid by the producer for that oil or gas, full consideration for purposes of (a) of this section includes the amount of the tax reimbursement received by the producer.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

15 AAC 55.163. Valuation of oil run through a North Slope field topping plant

(a) This section applies to oil run through a field topping plant in the Alaska North Slope area that is not returned and blended back into a production stream upstream of a point of production for oil.

(b) The gross value per barrel at the point of production for the oil is the prevailing value for that month determined under 15 AAC 55.171(g) multiplied by 1.2.

(c) The gross value determined under this section includes and is in place of the value of all pertinent cash receipts and disbursements between the owners of a field topping plant and the working interest owners of the oil run through the field topping plant.

History: Eff. 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.150

AS 43.55.190

15 AAC 55.165. Estimated payment of taxes based on market value for oil produced before 1/1/95

Repealed.

History: Eff. 9/1/84, Register 91; am 10/10/90, Register 116; am 2/14/91, Register 117; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.167. Transition rule for payment of estimated tax for third quarter 1990

Deleted.

History: Eff. 2/14/91, Register 117; deleted as of 1/2000, Register 152

Editor's note: As of Register 152 (January 2000), the regulations attorney deleted 15 AAC 55.167, a transitional provision, as obsolete.

15 AAC 55.170. Prevailing value for oil produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 9/1/84, Register 91; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.171. Prevailing value for oil, or commingled oil and NGLs

(a) The prevailing value for oil, or commingled oil and NGLs, produced in the Alaska North Slope area ("ANS") and delivered to the United States West Coast, including Hawaii, is

(1) for oil, or commingled oil and NGLs, that are transferred by the producer in an arm's-length, third party sale, the average spot price for ANS at the United States West Coast during the month that is referenced in the sales contract pricing provision; if more than one month is referenced in the sales contract pricing provision, the month with more daily spot price reports that fall within the contract price reference period must be used; in the case of an equal number of spot price reports, the month closer to the month of production must be used; if the sales contract has no price reference period, the prevailing value determined under (3) of this subsection must be used;

(2) for oil, or commingled oil and NGLs, that are transferred by the producer in an arm's-length, third party exchange, the average spot price for ANS at the United States West Coast during the same month that is applied under 15 AAC 55.161(c) to the crude received in the exchange; if the department cannot determine the month in which the crude was received, the prevailing value determined under (3) of this subsection must be used; or

(3) for other oil, or commingled oil and NGLs, including that which is refined, used as fuel or petrochemical feedstock, or otherwise consumed at a refinery or plant owned by the producer, the average spot price for ANS at the United States West Coast during the month of delivery of that oil, or commingled oil and NGLs.

(b) Repealed 1/1/2000.

(c) Repealed 1/1/2000.

(d) Repealed 1/1/2000.

(e) Repealed 1/1/2000.

(f) The prevailing value for ANS sold in the state at tidewater or delivered to coastal refineries in the state is the prevailing value determined in (a) of this section minus the volume-weighted average location differential between the Port of Valdez and the United States West Coast provided for under contracts for the sale of ANS delivered in the state during the previous calendar year. The department will calculate the annual volume-weighted average location differential by analyzing contracts entered into during the 18-month period ending November 30 of the previous calendar year for the sale of producers' ANS delivered in the state. The department will use contracts that it has received from producers by January 15 of the current calendar year. The department will calculate the location differential and the number of barrels delivered under each contract. The differential for each contract will be multiplied by the total number of barrels delivered under that contract. The resulting totals for all contracts will be added together, and that sum will be divided by the total number of barrels delivered under all of the contracts. The resulting location differential is a per-barrel amount. The department will provide notice to the producers of the amount of the location differential no later than February 10 each year.

(g) The prevailing value for ANS sold at Trans Alaska Pipeline System ("TAPS") pump station number one or sold at the entrance to a publicly regulated pipeline other than TAPS is the prevailing value determined in (f) of this section minus the carrier ownership-weighted average of all applicable publicly filed pipeline tariffs and the quality bank differentials, not including the TAPS Valdez Marine Terminal Quality Bank, for oil, or commingled oil and NGLs, produced from the relevant lease or property and transported between the location of sale and the TAPS terminal in Valdez. If a carrier has more than one applicable publicly filed pipeline tariff, the lowest tariff filed by that carrier must be used in calculating the carrier ownership-weighted average.

(h) The prevailing value for ANS delivered to an inland refinery in the state is the prevailing value as determined in (f) of this section, minus the carrier ownership-weighted average of all applicable TAPS tariffs and the quality bank differentials, not including the TAPS Valdez Marine Terminal Quality Bank, for oil, or commingled oil and NGLs, transported between TAPS pump station number one and the TAPS terminal in Valdez, plus the carrier ownership-weighted average of all applicable publicly filed pipeline tariffs and the per-barrel quality bank adjustments for oil, or commingled oil and NGLs, transported between TAPS pump station number one and the refinery. If a carrier has more than one applicable publicly filed pipeline tariff, the lowest tariff filed by that carrier must be used in calculating the carrier ownership-weighted average.

(i) Repealed 1/1/2004.

(j) Repealed 1/1/2004.

(k) The prevailing value for oil, or commingled oil and NGLs, produced in the state and delivered to a location other than those specified in (a) or (f) - (j) of this section is the value of comparable crudes delivered to the same market, as adjusted for quality and location and measured by indices of current market value.

(*l*) Repealed 1/1/2000.

(m) For purposes of this section, the average spot price for ANS at the United States West Coast during a month is the average of the monthly average assessments for the month by *Platt's Oilgram Price Report,* Telerate online data providing service, and Reuters online data providing service, calculated to three decimal places using the automatic convention in the rounding command or function in commercially available software. If *Platt's Oilgram Price Report,* Telerate online data providing service, or Reuters online data providing service ceases to report daily assessments for ANS at the United States West Coast, the average spot price for ANS at the United States West Coast is the average of the monthly average assessments by all remaining reporting services. In this subsection, a monthly average assessment for a month is the average of the midpoints between a reporting service's high and low closing assessments for ANS at the United States West Coast for all days during the month for which closing assessments are reported.

(n) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 11/1/2000, Register 156; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

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15 AAC 55.172. Prevailing value for gas produced before 1/1/95

Repealed.

History: Eff. 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.173. Prevailing value for gas

(a) For gas, other than NGLs, delivered in the Alaska North Slope area, the prevailing value per Mcf is 10 percent of the prevailing value per barrel that would be determined under 15 AAC 55.171(g) for oil that is produced from the lease or property from which the gas is produced and that is sold at the entrance to the publicly regulated oil pipeline serving that lease or property. If during the month that the gas is delivered oil is not produced from that lease or property and delivered into a publicly regulated oil pipeline serving that lease or property, the prevailing value calculation must be made with respect to the nearest lease or property from which oil is produced and delivered that month into a publicly regulated oil pipeline.

(b) For gas, other than NGLs, delivered in the Cook Inlet area during a calendar quarter, the prevailing value is the weighted average price of significant sales of gas from producers of gas to publicly regulated utilities in the Cook Inlet area for the three month period ending one month before the end of the previous calendar quarter. The department will publish on the 15th day of each calendar quarter the prevailing value for that quarter. For purposes of this subsection, "significant sales" means sales of 10,000 Mcf per month or more.

(c) For gas, other than NGLs, delivered in a foreign market, the prevailing value for the month of production of that gas is the weighted average sales price of all gas from the state sold in arm's-length, third party transactions in the month of delivery in the same market.

(d) For gas, other than NGLs, delivered in the United States outside the state, the prevailing value for the month of production of that gas is the weighted average sales price of all gas from the state sold in arm's-length, third party transactions in the month of delivery in the same market.

(e) For gas, other than NGLs, produced and either used by the taxpayer as fuel or feedstock in the production of urea or ammonia or exchanged on a volumetric basis for other gas used by the taxpayer as fuel or feedstock in the production of urea or ammonia, the prevailing value at the urea or ammonia plant is $1.30 per Mcf, as adjusted for the current month by multiplying $1.30 per Mcf by a fraction whose numerator is the average ammonia price for the previous three calendar months and whose denominator is $130 per short ton (2,000 pounds). For purposes of this subsection, the average ammonia price means the simple numerical average, for the three calendar month period immediately preceding production, of the weekly mid-point domestic prices per short ton (2,000 pounds) of anhydrous ammonia F.O.B. the United States Gulf Coast as reported in the table entitled "Green Markets Price-Scan U.S. Domestic Spot Quotes" in the publication *Green Markets*.

(f) The prevailing value for NGLs, other than NGLs that are commingled with oil before being tendered to a common carrier pipeline or before being transported from the lease or property, will be determined by the department on a case-by-case basis under AS 43.55.020 (f).

(g) A producer that sells gas in the Cook Inlet area or outside the state shall, at the time the producer files a production tax return, file a copy of the sales invoice for each transaction for the month covered by the return and a copy of any contract for the transactions that the producer enters into during the month covered by the return.

(h) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

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15 AAC 55.175. Allocation of value between oil and NGLs

(a) In calculating the gross value at the point of production for oil and for NGLs subject to 15 AAC 55.151(i) , a producer shall allocate the commingled-oil-and-NGLs netback value determined under that subsection between the oil and the NGLs by using the following equations:

VOIL = VBLEND + (VOLNGL * (QBVOIL - QBVNGL) / (VOLNGL + VOLOIL))

VNGL = VOIL - (QBVOIL - QBVNGL)

where

VOLNGL = the quantity, as calculated under 15 AAC 55.115(a) (6) if applicable, of NGLs produced from the lease or property by the producer during the month and commingled with oil before being tendered to a common carrier or before being transported from the lease or property;

VOLOIL = the quantity, as calculated under 15 AAC 55.115(a) (7) if applicable, of oil produced from the lease or property by the producer during the month and commingled with NGLs before being tendered to a common carrier or before being transported from the lease or property;

VBLEND = the commingled-oil-and-NGLs netback value determined under 15 AAC 55.151(i) ;

QBVNGL = the value determined under (b) of this section;

QBVOIL = the value determined under (c) of this section;

VOIL = the value for the oil, from which is subtracted the upstream portion of the costs of transportation, if any, as calculated for the oil under 15 AAC 55.151(i) to obtain the gross value at the point of production; and

VNGL = the value for the NGLs, from which is subtracted the upstream portion of the costs of transportation, if any, as calculated for the NGLs under 15 AAC 55.151(i) to obtain the value used in 15 AAC 55.151(b) (4)(C).

(b) In this section, QBVNGL for the month of production is the sum, over all NGL components as reported for the month under (e) of this section, of the product of the average volume percentage of each component in the NGLs reported times the component's reference price prescribed for the month by the Quality Bank methodology.

(c) In this section, QBVOIL for the month of production is the sum, over all components specified in the Quality Bank methodology, of the product of the average volume percentage of each component in the oil produced from the lease or property and commingled with NGLs during the month times the component's reference price prescribed for the month by the Quality Bank methodology. If the Quality Bank administrator issues a report pertaining to the commingled oil and NGLs produced from the lease or property during the month, the average volume percentage of each component in the oil must be derived as follows:

(1) the reported volume percentage of each component in the commingled oil and NGLs must be multiplied by the total volume of commingled oil and NGLs produced from the lease or property by all producers during the month; that total volume is the metered post-blending volume if 15 AAC 55.115 applies; if the Quality Bank administrator separately reports volume percentages for two or more separate streams of the commingled oil and NGLs from the lease or property, the calculation set out in this paragraph must be performed separately for each stream and the results then summed over the streams for each component;

(2) the average volume percentage of each component in the NGLs as reported under (e) of this section must be multiplied by the total quantity, as calculated under 15 AAC 55.115 if applicable, of NGLs produced from the lease or property by all producers during the month and commingled with oil;

(3) the volume of each component calculated under (2) of this subsection must be subtracted from the volume of that component calculated under (1) of this subsection to obtain the volume of that component in the oil;

(4) the volume of each component in the oil must be divided by the total quantity, as calculated under 15 AAC 55.115 if applicable, of oil produced from the lease or property by all producers during the month and commingled with NGLs, to obtain the average volume percentage of that component in the oil.

(d) If the Quality Bank administrator issues a report pertaining to commingled oil and NGLs produced from a lease or property during a month, the component reference prices used in calculating QBVNGL under (b) of this section and QBVOIL under (c) of this section must be the pertinent reference prices reported by the Quality Bank administrator.

(e) A producer that is also the operator of a gas processing plant extracting NGLs that are commingled with oil before being tendered to a common carrier or before being transported from the lease or property shall accurately measure the NGLs' composition each month by performing gas chromatography analyses substantially in accordance with the Gas Processors Association standard GPA 2186-95, *Tentative Method for the Extended Analysis of Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Temperature Programmed Gas Chromatography,* revised as of 1995 and adopted by reference. Based on the results of those analyses, the producer shall calculate, in accordance with (f) of this section, the average volume percentage of propane, isobutane, normal butane, light straight run (C5 - 175ø F.), and naphtha (175ø F. - 350ø F.). The producer shall

(1) submit to the department, as part of the statement filed under AS 43.55.030 , a report showing the results of the gas chromatography analyses and the average volume percentage of each component of the NGLs as calculated in accordance with (f) of this section; and

(2) within five days after submitting the report required in (1) of this subsection to the department, provide a copy of that report to each producer of

(A) oil with which NGLs extracted at the gas processing plant are commingled before being tendered to a common carrier or before being transported from the lease or property; and

(B) gas from which NGLs are extracted at the gas processing plant and commingled with oil before being tendered to a common carrier or before being transported from the lease or property.

(f) NGL composition must be determined from gas chromatography analyses according to the following classifications:

(1) a peak identified as C3 or lighter is classified as propane;

(2) the peak identified as isobutane is classified as isobutane;

(3) a peak identified as normal butane or butylene is classified as normal butane;

(4) a peak identified as C5 or C6 is classified as light straight run (C5 - 175ø F.);

(5) forty percent of the volume for a peak identified as C7 is classified as light straight run (C5 - 175ø F.);

(6) sixty percent of the volume for a peak identified as C7 is classified as naphtha (175ø F. - 350ø F.);

(7) a peak identified as C8 or heavier is classified as naphtha (175ø F. - 350ø F.); and

(8) an unidentified peak is classified as naphtha (175ø F. - 350ø F.).

(g) In this section,

(1) "Quality Bank methodology" means the Trans Alaska Pipeline System (TAPS) Quality Bank settlement methodology for TAPS pump station number one as approved by the Alaska Public Utilities Commission in its "Order Adopting Federal Energy Regulatory Commission Order Approving Contested Settlement; Rejecting Contested Settlements Filed by Tesoro Alaska Petroleum Company and Exxon Company, U.S.A.; Requiring Filing of Tariff Revisions; and Severing Docket P-96-6 for Separate Consideration," *In the Matter of the Formal Complaint of Tesoro Alaska Petroleum Company Against Amerada Hess Pipeline Corporation, et al.,* Docket Nos. P-89-1, *et al.,* Orders Nos. 87, *et al.* (Jan 13, 1998), as modified by the Regulatory Commission of Alaska in its "Order Designating Replacement Price and Authorizing Concurrent Settlement Proceedings on Processing Adjustment," *In the Matter of the Filing of a Notice of the Trans Alaska Pipeline System Quality Bank Administrator Concerning the Pricing of the Heavy Distillate Component on the West Coast,* Docket No. P-99-12, Order No. 2 (Feb. 8, 2000), and as described in Local Pipeline Tariff F.E.R.C. No. 52 of Amerada Hess Pipeline Corporation (Aug. 30, 2000), as modified by Local Pipeline Tariff

Supplement No. 2 to F.E.R.C. No. 52 of Amerada Hess Pipeline Corporation (Jan. 23, 2002); the Quality Bank methodology is adopted by reference in relevant part as an interim methodology; and

(2) "Quality Bank administrator" means the person that is designated and acts as Quality Bank administrator under the Quality Bank methodology.

(h) The Quality Bank methodology adopted by reference in relevant part in this section is an interim methodology only, pending the department's adoption by regulation of a permanent methodology in light of further proceedings before the Federal Energy Regulatory Commission on remand from the United States Court of Appeals in *Exxon Co., U.S.A. v. Federal Energy Regulatory Commission,* 182 F.3d 30 (D.C. Cir. 1999). A producer's allocation of commingled-oil-and-NGLs netback values between oil and NGLs under this section is subject to retroactive adjustment after the department adopts a permanent methodology.

(i) The following example illustrates (a), (b), and (c) of this section:

Step One from (c)(1) of this section:

Input 1: Production (number of barrels):

a.	Oil (VOLOIL)*	567,000	576,000	1,143,000
b.	NGLs (VOLNGL)**	90,000	34,000	124,000
c.	Total	657,000	610,000	1,267,000

* From steps 9A and 9B of example in 15 AAC 55.115(d)

** From steps 8A and 8B of example in 15 AAC 55.115(d)

Input 2: Component Percentage of Oil/NGL Blend

(To be taken from Quality Bank report)

a.	Propane	0.70%
b.	Isobutane	1.10%
c.	Normal Butane	3.30%
d.	Light Straight Run	7.80%
e.	Naphtha	20.30%
f.	Light Distillate	9.10%
g.	Heavy Distillate	18.30%
h.	Gas Oil	25.20%
i.	Resid	14.20%
	Total	100.00%

Calculation 1: Component Volumes for the Oil/NGL Blend

(Input 1c total times Input 2)

a.	Propane	8,869.000000000
b.	Isobutane	13,937.000000000
c.	Normal Butane	41,811.000000000
d.	Light Straight Run	98,826.000000000
e.	Naphtha	257,201.000000000
f.	Light Distillate	115,297.000000000
g.	Heavy Distillate	231,861.000000000
h.	Gas Oil	319,284.000000000
i.	Resid	179,914.000000000
	Total	1,267,000.000000000

Step Two from (c)(2) of this section:

Input 3: Component Percentages of NGLs

(To be supplied by operator of gas processing plant)

a.	Propane	2.900%
b.	Isobutane	10.270%
c.	Normal Butane	31.220%
d.	Light Straight Run	46.400%
e.	Naphtha	9.210%
	Total	100.000%

Calculation 2: Component Volumes for the NGLs

(Input 1b total times Input 3)

a.	Propane	3,596.000000000
b.	Isobutane	12,734.800000000
c.	Normal Butane	38,712.800000000
d.	Light Straight Run	57,536.000000000
e.	Naphtha	11,420.400000000
f.	Light Distillate	.000000000
g.	Heavy Distillate	.000000000
h.	Gas Oil	.000000000
i.	Resid	.000000000
	Total	124,000.000000000

Step Three from (c)(3) of this section:

Calculation 3: Component Volumes for Oil

(Calculation 1 minus Calculation 2)

a.	Propane	5,273.000000000
b.	Isobutane	1,202.200000000
c.	Normal Butane	3,098.200000000
d.	Light Straight Run	41,290.000000000
e.	Naphtha	245,780.600000000
f.	Light Distillate	115,297.000000000
g.	Heavy Distillate	231,861.000000000
h.	Gas Oil	319,284.000000000
i.	Resid	179,914.000000000
	Total	1,143,000.000000000

Step Four from (c)(4) of this section:

Calculation 4: Component Percentage of Oil

(Calculation 3 divided by Input 1a total)

a.	Propane	0.461329830%
b.	Isobutane	0.105179350%
c.	Normal Butane	0.271058620%
d.	Light Straight Run	3.612423450%
e.	Naphtha	21.503114610%
f.	Light Distillate	10.087226600%
g.	Heavy Distillate	20.285301840%
h.	Gas Oil	27.933858270%
i.	Resid	15.740507440%
	Total	100.000000000%

Step Five from (b) and (d) of this section:

Input 4: Component Prices

(To be taken from Quality Bank report)

a.	Propane	$12.45
b.	Isobutane	$18.47
c.	Normal Butane	$10.46
d.	Light Straight Run	$14.24
e.	Naphtha	$15.54

f.	Light Distillate	$18.85
g.	Heavy Distillate	$17.81
h.	Gas Oil	$15.63
i.	Resid	$9.67

Calculation 5: Component Values of the Oil Stream

(Input 4 times Calculation 4)

a.	Propane	$0.057435560
b.	Isobutane	$0.019426630
c.	Normal Butane	$0.028352730
d.	Light Straight Run	$0.514409100
e.	Naphtha	$3.341584010
f.	Light Distillate	$1.901442210
g.	Heavy Distillate	$3.612812260
h.	Gas Oil	$4.366062050
i.	Resid	$1.522107070
	Total (QBVOIL)	$15.36

Step Six from (c) and (d) of this section:

Calculation 6: Component Values of the NGL Stream

(Input 4 times Imput 3)

a.	Propane	$ 0.361050000
b.	Isobutane	$ 1.896869000
c.	Normal Butane	$ 3.265612000
d.	Light Straight Run	$ 6.607360000
e.	Naphtha	$ 1.431234000
f.	Light Distillate	.000000000
g.	Heavy Distillate	.000000000
h.	Gas Oil	.000000000
i.	Resid	.000000000
	Total (QBVNGL)	$ 13.56

Step Seven from (a) of this section:

Input 5: Average Producer Value

Average Producer Value (V**BLEND)** $10.18 $9.98

Solve the equations:

PRODUCER A

Equation 1

$$V_{OIL} = V_{BLEND} + (VOL_{NGL} * (QBV_{OIL} - QBV_{NGL}) / (VOL_{NGL} + VOL_{OIL}))$$

$$V_{OIL} = \$10.18 + (90{,}000 \text{ bbls} * (\$15.36 - \$13.56) / (90{,}000 \text{ bbls} + 567{,}000 \text{ bbls}))$$

$$V_{OIL} = \$10.43$$

Equation 2

$$V_{NGL} = V_{OIL} - (QBV_{OIL} - QBV_{NGL})$$

$$V_{NGL} = \$10.43 - (\$15.36 - \$13.56)$$

$$V_{NGL} = \$8.63$$

PRODUCER B

Equation 1

$$V_{OIL} = V_{BLEND} + (VOL_{NGL} * (QBV_{OIL} - QBV_{NGL}) / (VOL_{NGL} + VOL_{OIL}))$$

$$V_{OIL} = \$9.98 + (34{,}000 \text{ bbls} * (\$15.36 - \$13.56) / (34{,}000 \text{ bbls} + 576{,}000 \text{ bbls}))$$

$$V_{OIL} = \$10.08$$

Equation 2

$$V_{NGL} = V_{OIL} - (QBV_{OIL} - QBV_{NGL})$$

$$V_{NGL} = \$10.08 = (\$15.36 - \$13.56)$$

V<u>NGL</u> = $8.28

Note to example:

Components are those specified in the Quality Bank methodology.

History: Eff. 1/1/2000, Register 152; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.016

AS 43.55.020

AS 43.55.030

AS 43.55.110

Editor's note: GPA 2186-95, adopted by reference in 15 AAC 55.175,

may be reviewed during business hours at the Alaska Department of Revenue Oil and Gas Audit Division, 550 W. Seventh Avenue, Suite 500, Anchorage, AK 99501, and may be obtained from the Gas Processors Association, 6526 East 60th Street, Tulsa, Ok 74145. The Alaska Public Utilities Commission and Regulatory Commission of Alaska orders and the tariff documents that describe the "Quality Bank methodology" adopted in relevant part by reference in 15 AAC 55.175

may be reviewed during business hours at the Alaska Department of Revenue Oil and Gas Audit Division, 550 W. Seventh Avenue, Suite 500, Anchorage, AK 99501, and they may be reviewed and copies may be obtained at the Regulatory Commission of Alaska, 701 W. Eighth Avenue, Suite 300, Anchorage, AK 99501.

15 AAC 55.180. Choice of methods for determining reasonable cost of transportation

(a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in 15 AAC 55.191(a) and (b), if the actual costs incurred are ordinary and necessary transportation expenses.

(b) The reasonable cost of transportation is the fair market value as defined in 15 AAC 55.191(h) if all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

History: Eff. 1/6/80, Register 73; am 1/1/95, Register 132; am 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

15 AAC 55.190. Calculation of reasonable costs of transportation for oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.191. Calculation of reasonable costs of transportation for oil or gas

(a) Reasonable costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas from the point of production to the sales delivery point or, if gas has been run through a gas processing plant, from the plant to the sales delivery point.

(b) Actual costs of transportation allowable for purposes of 15 AAC 55.180(a) are

(1) if transportation of oil or gas is by a regulated carrier, the tariff that is on file with the Federal Energy Regulatory Commission or other regulatory agency having jurisdiction, and that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) if transportation of oil is by a vessel that is not owned or effectively owned, in whole or in part, by the producer of that oil

(A) for a single voyage charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning costs, if any, borne by the producer for that vessel;

(B) for a consecutive voyage charter or a time charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning cost, if any, borne by the producer for that vessel; the positioning cost must be amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter; or

(C) for a contract of affreightment, the total costs under the contract, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the contract of affreightment, are not included in the charter fee, and are borne by the producer, plus any positioning costs not included in that fee that are incurred with respect to that transportation during the contract of affreightment and that are borne by the producer;

(3) if transportation of oil is by a vessel that is owned or effectively owned, in whole or in part, by the producer of that oil, the producer's actual cost for that transportation, which is the sum of

(A) voyage and port costs incurred with respect to that transportation, as provided in (j) of this section;

(B) the positioning cost, amortized over 36 months, for that vessel;

(C) depreciation of the vessel as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), (c), (f), or (h) or 15 AAC 55.196, as applicable; and

(D) an amount that, when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost, as provided in 15 AAC 55.195(a) , of the vessel over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost or invested capital as provided in 15 AAC 55.195(b) , (c), (f), or (h) or 15 AAC 55.196, as applicable;

(4) in the case of transportation of gas as liquefied natural gas (LNG),

(A) if not all of the LNG transportation facilities are subject to tariff regulations of the Federal Energy Regulatory Commission or another federal agency, a state, territory, or possession of the United States, or a foreign nation, and if the producer does not own or effectively own, in whole or in part, the LNG transportation facility, the amount charged to the producer for that LNG transportation;

(B) if the producer owns or effectively owns, in whole or in part, the LNG transportation facility, the producer's actual cost for that transportation, which is the sum of

(i) the direct operating costs of the LNG transportation facility incurred with respect to the producer's gas; for an LNG tanker, direct operating costs consist of the tanker's voyage and port costs as provided in (j) of this section;

(ii) the positioning cost, amortized over 36 months, in the case of an LNG tanker;

(iii) depreciation of the LNG transportation facility as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable;

(iv) an amount that, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost, as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable, of the LNG transportation facility over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable;

(5) if transportation of oil or gas is by a nonregulated pipeline facility that is not owned or effectively owned, in whole or in part, by the producer of that oil or gas, the transportation fee specified in the contract plus any other costs not included in the fee with respect to that transportation that are borne by the producer;

(6) if transportation of gas is by a nonregulated pipeline facility that is owned or effectively owned, in whole or in part, by the producer of that gas, that transports residue gas from a gas processing plant, and that was first placed in service 30 or fewer years before the month of production, a presumed cost of $0.01 per Mcf of taxable residue gas;

(7) if transportation of gas is by a nonregulated pipeline facility that is owned or effectively owned, in whole or in part, by the producer of that gas, that transports NGLs from a gas processing plant, that includes a facility that blends NGLs with oil, and that was first placed in service 30 or fewer years before the month of production, a presumed cost of $.15 per barrel of taxable NGLs; or

(8) if transportation of oil or gas is by a nonregulated pipeline facility, other than one described in (6) or (7) of this subsection, that is owned or effectively owned, in whole or in part, by the producer of that oil or gas, or if a producer of gas transported by a facility described in (6) or (7) of this subsection elects not to use the presumed cost under that paragraph, the sum of the following, allocated to that oil or gas in the proportion that the volume of that oil or gas bears to the total volume of fluids transported by the pipeline:

(A) a cost of capital allowance that includes depreciation and a return on investment, as provided in 15 AAC 55.195(d) ;

(B) the reasonable operating and maintenance costs for the pipeline facility, which are determined by multiplying the projected actual annual amount of direct operating and maintenance costs for the pipeline facility by 112 percent; for purposes of this subparagraph, direct operating and maintenance costs are only those costs necessary to physically operate and maintain the pipeline facility;

(C) ad valorem taxes associated with the pipeline facility.

(c) Repealed 1/1/2000.

(d) Repealed 1/1/2000.

(e) Repealed 1/1/2000.

(f) Repealed 1/1/2000.

(g) Repealed 1/1/2000.

(h) Reasonable cost of transportation under 15 AAC 55.180(b) is fair market value. Fair market value of transportation is determined

(1) for shipments of oil, on the basis of third-party charters (that is, time charters in which the producer does not own or effectively own the vessel in whole or in part) of one year or more which are reported to the department for like vessels, plus regulated transportation costs under (b)(1) of this section; two vessels will be considered like vessels if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both

(A) Jones Act vessels (46 U.S.C. App. 808 and 883);

(B) Construction-Differential Subsidy ("CDS") vessels (46 U.S.C. App. 1151 - 1161);

(C) Operating-Differential Subsidy ("ODS") vessels (46 U.S.C. App. 1171 - 1185);

(D) CDS and ODS vessels; or

(E) vessels that do not meet the qualifications of (A) - (D) of this paragraph; or

(2) for shipments of gas as LNG, on the basis of third party charters or leases (that is, time charters or leases in which the producer does not own or effectively own, in whole or in part, the LNG transportation facility in question) of three years or more that are reported to the department for like LNG transportation facilities, plus regulated transportation costs under (b)(1) of this section.

(i) If a producer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of the sale the producer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the producer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the producer were the shipper. This subsection does not apply if the producer's expected repurchase does not in fact occur.

(j) For purposes of this section, allowable voyage and port costs for a vessel do not include losses, damages, or expenses incurred in connection with an oil discharge except as provided in this subsection, and do not include taxes or fees on the receipt of oil or LNG at a marine terminal from a vessel. Allowable voyage and port costs for a vessel or LNG tanker are costs actually incurred for the following purposes:

(1) fuel for the vessel or LNG tanker while in port and at sea not to exceed the actual cost if purchased from a third party, or if the fuel is not purchased from a third party, the spot market price of comparable fuel as reported in Platt's Oilgram Price Report at the time of the fuel purchase for the market nearest the point of refueling, plus related allowable fuel taxes and handling charges;

(2) stores and provisions for the vessel or LNG tanker and its captain and crew

(3) wages and benefits of the vessel's or LNG tanker's captain and crew;

(4) routine maintenance;

(5) drydocking costs, expensed in the year paid;

(6) port and dock fees;

(7) repealed 1/1/2002;

(8) demurrage;

(9) tug and pilotage fees;

(10) marine agents' fees in port;

(11) lightering;

(12) transshipment charges;

(13) customs fees and duties;

(14) taxes incurred due to the ownership and operation of the vessel or LNG tanker, except for income taxes and other taxes (including certain franchise taxes) measured by income;

(15) regular and customary gratuities that are also legal;

(16) insurance premiums actually paid to third-party insurers;

(17) minor cargo losses or measuring differentials not to exceed .0025 of the oil transported, determined on an annual basis for each vessel;

(18) loading and unloading inspection fees;

(19) Panama Canal transit fees;

(20) a reasonable management fee for operating vessels or LNG tankers; this fee is set at six percent of the allowable costs set out in (1) - (3) of this subsection; this set fee covers all general and administrative costs related to vessel operations, including all costs for accounting services, clerical services, administrative services, secretarial services, data processing services, legal services, corporate and operations management, overhead pass-throughs, facility costs and depreciation, corporate planning, risk management, environmental planning and risk evaluation, public affairs, governmental affairs, political affairs, dues and subscriptions other than dues allowable under (22) of this subsection, long-range scheduling, and long-range planning; additional deductions will not be allowed for these costs;

(21) other costs directly associated with the operation or maintenance of the vessel or LNG tanker, including costs for port services and operations, cargo scheduling and planning, fleet staffing, fleet scheduling, fleet staff training, fleet safety, engineering for repair, engineering for maintenance, engineering for drydocking, quality assurance for vessel operations, communication systems, navigation systems, United States Coast

Guard certifications, and utility services; these costs include costs for personnel performing the functions listed and the first level of supervision of these personnel;

(22) costs incurred in transportation of oil to comply with 33 U.S.C. 2701 - 2761 (Oil Pollution Act of 1990), AS 46.04, and applicable laws of this or any other state or political subdivision requiring equipment and personnel to be in place for spill prevention and response to spills from vessels; those costs must have not been incorporated into a pipeline tariff, but must have been incurred as an actual cost in the transportation of oil produced in the state; and

(23) costs of containing and cleaning up cargo lost in a discharge, unless the discharge is a catastrophic oil discharge under AS 46.04.900 .

(k) For purposes of this section, a producer "effectively owns" a vessel, LNG transportation facility, or nonregulated pipeline facility if the vessel, LNG transportation facility, or nonregulated pipeline facility

(1) is owned by another person comprising part of a consolidated business in which the producer is also a part;

(2) is the subject of a lease that qualifies as a capital lease under generally accepted accounting principles, in which the producer or another person comprising part of a consolidated business in which the producer is also a part, is the lessee;

(3) was built to the account of the producer, or of another person comprising part of a consolidated business in which the producer is also a part, was sold and was chartered or leased back by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, all in a simultaneous transaction, and is on a term charter or lease for a period of 15 years or longer to the producer, or to another person comprising part of a consolidated business in which the producer is also a part; or

(4) in the case of a vessel for which a cost of capital allowance is allowed under 15 AAC 55.196, is treated as owned by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, in a federal income tax return filed by or on behalf of the producer, or by or on behalf of another person comprising part of a consolidated business in which the producer is also a part.

(*l*) For purposes of this section, the "positioning cost" for a vessel or LNG tanker includes the costs borne by the producer for placing that vessel or LNG tanker into position before the vessel's or LNG tanker's first voyage in service for that producer.

(m) The third-party nature of an agreement between a producer and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that producer and carrier into a consolidated business, if, at the time they entered into that agreement, neither the producer nor the carrier exercised directly or indirectly any control over the business affairs of the other.

(n) The producer's actual marine transportation cost, as otherwise determined under this section, for a producer that transports oil produced in the state on behalf of a non-affiliated party through a charter, contract of affreightment, sublease, or other arrangement, in addition to the producer's own oil produced in the state, includes the cost of transporting that non-affiliated party's oil produced in the state and is reduced by the revenue received for providing that transportation. For purposes of this subsection,

(1) "affiliated party" means a company effectively controlled by the producer or by the same company that effectively controls the producer; a company "effectively controls" another company if it directly or indirectly owns 20 percent or more of the outstanding stock or other ownership interests;

(2) "non-affiliated party" means a producer of oil produced in the state that is not an affiliated party.

(o) A producer shall report any reimbursed costs to the department. Reimbursed costs are not allowable as actual costs of transportation under this section.

(p) Only costs incurred in the transportation of oil or gas produced from a lease or property in the state are allowable costs. Costs incurred in connection with the transportation of any other oil or gas are not allowable costs.

(q) For purposes of this section, "expected useful life" means the period of time used to calculate depreciation under (b)(3)(C) or (b)(4)(B)(iii) of this section.

(r) Repealed 1/1/2002.

(s) Repealed 1/1/2000.

(t) In this section, "oil" includes commingled oil and NGLs.

(u) For oil or gas produced during calendar year 2002 that is transported by a vessel placed in service on or after January 1, 1995, the actual costs of transportation under (b) of this section do not include depreciation, return on acquisition cost, or lease or charter payments for a vessel or LNG tanker that has not, during any period of 60 consecutive days or longer, retroactive to the first day of the period, transported oil or gas produced in the state. However, if the vessel is placed in dry dock before the end of the 60-day period, the actual costs of transportation under (b) of this section do not include depreciation, return on investment, or lease or charter payments for the vessel if it has not, during any period of more than 120 consecutive days, transported oil or gas produced in the state, with the disallowance of the costs of transportation starting with the 121st day.

(v) Other costs incurred to transport oil or gas from the flange of the vessel to the sales delivery point are allowable for purposes of 15 AAC 55.180(a) if the other costs are actual costs of transportation.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

AS 43.55.900

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15 AAC 55.195. Return on investment or cost of capital allowance to be used in calculation of reasonable costs of transportation for oil or gas, other than certain vessel transportation costs for oil or gas produced on or after January 1, 2003

(a) For a vessel, LNG transportation facility, or capitalized improvement placed in service before January 1, 1995, by the producer or by a person from whom, directly or through an intermediate transaction of the same nature, the producer later acquired the vessel as part of a larger transfer of both marine and non-marine assets associated with a business merger or acquisition transaction, a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D) or 15 AAC 55.191(b) (4)(B)(iii) and (iv) is an amount that yields a return on the acquisition cost of the vessel, LNG transportation facility, or capitalized improvement, after federal income tax, of two percent plus the average annual national inflation rate, measured by the compound root of the GNP deflator, during the period between the time the commitment was made to construct or initially acquire the vessel, LNG transportation facility, or capitalized improvement for the purpose of placing it in service and the time when the vessel, LNG transportation facility, or capitalized improvement had been received or delivered and was ready to be placed into service, or if that period fell entirely within a calendar year, during that entire calendar year, except that if the department replaced that rate of return with a different rate of return for a vessel, LNG transportation facility, or capitalized improvement under former 15 AAC 55.190(i), that different rate of return is allowed instead. The allowance for the reasonable return on the acquisition cost is a level annual amount, determined in the year of initial acquisition for the purpose of placement in service, considering the marginal federal corporate income tax rate in effect that year and the contemporaneous and projected federal income tax benefits. If, in subsequent years, the federal tax rate changes, or other events occur that change the available federal income tax benefits, a revised level annual allowance must be calculated to yield the same after-tax return. For purposes of this subsection,

(1) "acquisition cost" means the amount, not to exceed the cost of the vessel, LNG transportation facility, or capitalized improvement when initially acquired for the purpose of placing it in service, capitalized by the item's actual or effective owner under generally accepted accounting principles, including costs of improvements made after the date a vessel or LNG transportation facility was initially placed in service, and reduced by the

(A) cash value of any federal income tax benefits, such as investment tax credit, of acquiring the vessel, LNG transportation facility, or capitalized improvement; and

(B) reasonable salvage value of the vessel, LNG transportation facility, or capitalized improvement;

(2) "after federal income tax" means after applying appropriate adjustments for the federal income tax benefits of owning and operating the vessel, LNG transportation facility, or capitalized improvement; these tax benefits include tax depreciation, foreign

tax credits generated by foreign source income derived from the use of the vessel, LNG transportation facility, or capitalized improvement, capital construction fund contributions, and investment tax credits.

(b) For a vessel or LNG transportation facility placed in service on or after January 1, 1995, and before January 1, 2002, or for a capitalized improvement placed in service on or after January 1, 1995, and before January 1, 2002, that extends the life of a vessel or LNG transportation facility, (1) a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D) or 15 AAC 55.191(b) (4)(B)(iii) and (iv) is $99,000 per year for 24 years for each $1,000,000 of adjusted shipyard cost, for oil or gas produced before January 1, 2002; and (2) a cost of capital allowance will be allowed as provided in (d) or (f) of this section or 15 AAC 55.196, as applicable, for oil or gas produced on or after January 1, 2002. For purposes of this subsection, "adjusted shipyard cost" means the total amount paid to the person building or selling the vessel, LNG transportation facility, or capitalized improvement to the producer, less any investment tax credit taken by the producer, or in the case of an effectively owned vessel or LNG transportation facility, taken by the legal owner of that vessel or facility and passed on in whole or in part to the producer through reduced charter-hire or lease payments, and less any salvage value used by the producer to compute depreciation expense reported to shareholders and owners. If a vessel, LNG transportation facility, or capitalized improvement is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed. If a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(c) For a capitalized improvement placed in service on or after January 1, 1995 and before January 1, 2002, that does not extend the life of a vessel or LNG transportation facility,

(1) a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D) or 15 AAC 55.191(b) (4)(B)(iii) and (iv) is $158,000 per year for 10 years for each $1,000,000 of adjusted shipyard cost as defined in (b) of this section, for oil or gas produced before January 1, 2002, and on or after January 1, 2003; and

(2) a cost of capital allowance will be allowed as provided in (d) or (h) of this section, as applicable, for oil or gas produced during calendar year 2002.

(d) For an LNG transportation facility or capitalized improvement to that facility first placed in service by the producer on or after January 1, 1995, a cost of capital allowance that consists of depreciation and a return on acquisition cost will be allowed for oil or gas produced on or after January 1, 2002. The cost of capital allowance under this subsection is also available for a pipeline facility under 15 AAC 55.191(b) (8), or for a capitalized improvement that is made to that facility. However, an improvement to an LNG transportation or pipeline facility that the producer treats as an expense under 26 U.S.C. 179 may not receive a cost of capital allowance under this subsection. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated

(A) using the following formula, except as provided in (B) of this paragraph: cost of capital allowance = initial cash flow/(1 - marginal federal tax rate); and

(B) for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, the cost of capital allowance equals the total after-tax cash flow;

(2) for purposes of the formulas set out in (1) and (8) of this subsection, initial cash flow is calculated using the following formula: initial cash flow = (remaining unrecovered investment - after-tax present value of future tax depreciation benefits)/present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = (finance cost - total after-tax cash flow) * ((1 + WACC) *exp.* (portion of year in service * 0.5));

(4) for purposes of the formula set out in (3) of this subsection, finance cost is calculated using the following formula: finance cost = remaining unrecovered investment from the prior year * ((1 + WACC) *exp.* (portion of year in service * 0.5));

(5) the remaining unrecovered investment from the prior year, for purposes of the formula set out in (4) of this subsection, and for

(A) the first year the facility is in service, is the sum of the unrecovered investments for all years the facility is under construction; and

(B) a facility that is in service on January 1, 2002, is calculated using the method set out in this subsection and as if the facility received the cost of capital allowances provided in this section for the facility's years of service before January 1, 2002;

(6) for purposes of (5)(A) of this subsection, an unrecovered investment for a year the facility is under construction is calculated as if the facility were built over a two-year period before the first month the facility is first placed in service, with equal amounts paid each year; unrecovered investment for a year the facility is under construction is calculated using the following formula: unrecovered investment for a year the facility is under construction = total amount paid to the person building or selling the facility to the producer * 0.5 * portion of the calendar year the facility is under construction * finance factor during construction;

(7) for purposes of the formula set out in (6) of this subsection, the finance factor during construction is calculated as if the facility were built over a two-year period before the first month the facility is first placed in service; the finance factor during construction is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, and except as provided in (B) of this paragraph, the finance factor during construction = ((1 + WACC for the first calendar year of construction) = it exp. (portion of the first calendar year the facility is in service * 0.5)) * (1 + WACC for the second calendar year of construction) * ((1 + WACC for the third calendar year of construction) = it exp. (1 - the portion of the first calendar year the facility is in service));

(B) for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, the finance factor during construction is calculated as if the portion of the first calendar year the facility is in service is zero;

(C) for the second calendar year of construction, the finance factor during construction = ((1 + WACC for the second calendar year of construction) *exp.* (0.5)) * ((1 + WACC for the third calendar year of construction) *exp.* (1 - the portion of the first calendar year the facility is in service));

(D) for the portion of the third calendar year of construction, the finance factor during construction = (1 + WACC for the third calendar year of construction) *exp.* ((1 - the portion of the first calendar year the facility is in service) * 0.5);

(8) for purposes of (1)(B) of this subsection and the formula set out in (3) of this subsection, total after-tax cash flow is calculated using the following formula: total after-tax cash flow = initial cash flow + after-tax cash flow of depreciation benefits for that tax year;

(9) for purposes of the formula set out in (8) of this subsection, after-tax cash flow of depreciation benefits for that tax year

(A) except as provided in (B) of this paragraph, is calculated using the following formula: after-tax cash flow of depreciation benefits for that tax year = total amount paid to the person building or selling the facility to the producer * marginal federal tax rate * federal depreciation factor; and

(B) equals zero, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(10) for purposes of the formulas set out in (9) and (12) of this subsection, the federal depreciation factor is the percentage of the total amount paid to the person building or selling the facility to the producer that can be depreciated for federal corporate income tax for the tax year;

(11) for purposes of (2) of this subsection, the after-tax present value of future tax depreciation benefits

(A) except as provided in (B) of this paragraph, is the sum of the discounted annual tax depreciation amounts for each remaining year in which the total amount paid to the person building or selling the facility to the producer can be depreciated for federal corporate income tax for the tax year; and

(B) equals zero, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(12) for purposes of (11) of this subsection, a discounted annual tax depreciation amount is calculated using the following formula: discounted annual tax depreciation amount = federal depreciation factor * total amount paid to the person building or selling the facility to the producer * marginal federal tax rate * discount factor;

(13) for purposes of the formulas set out in (1), (9), and (12) of this subsection, the marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 35 percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(14) for purposes of the formula set out in (12) of this subsection, the discount factor is calculated using the following formula: discount factor = 1/((1 + WACC) *exp.* (discount factor exponent));

(15) for purposes of the formula set out in (14) of this subsection, the discount factor exponent is calculated using the following formula: discount factor exponent = (((((1 - portion of year in service) + 1) * 0.5) - 1) + year depreciation benefit is realized);

(16) for purposes of the formula set out in (2) of this subsection, the present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC, is the result generated by the following formula: (((1 - (1/((1+WACC) *exp.* (years of remaining life))))/WACC)/((1+WACC) *exp.* (-0.5)))/portion of year in service;

(17) for purposes of the formula set out in (16) of this subsection, years of remaining life must be determined for each

(A) component of the facility that is in service at the start-up of the facility as if that component had a 30-year life, except that for LNG transportation facilities first placed in service on or after January 1, 1995 and before January 1, 2002, years of remaining life must be determined, for each year before January 1, 2002, as if that component had a 24-year life;

(B) capitalized improvement that extends the life of a facility and that is put in service after start-up of the facility as if that capitalized improvement had a 15-year life; and

(C) capitalized improvement that does not extend the life of a facility and that is put in service after start-up of the facility as if that capitalized improvement had a 10-year life;

(18) for purposes of the formulas set out in (2), (3), (4), (7), (14), and (16) of this subsection, WACC or the weighted average cost of capital,

(A) for a calendar year before 1997,

(i) except as provided in (ii) of this subparagraph, is 10 percent; and

(ii) is eight percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002; and

(B) for 1997 or a later calendar year,

(i) except as provided in (ii) of this subparagraph, is the cost of capital, as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, *Standard Industrial Classification Manual,* as revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this sub-subparagraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Ibbotson Associates *The Cost of Capital Yearbook* published during the previous calendar year, plus, for LNG transportation facilities, 0.2 percent after December 31, 2001; and;

(ii) is eight percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(19) for purposes of the formula set out in (16) of this subsection, for facilities that come into service midyear, the portion of the year in service for the first and last calendar years the facility is in service is the number of days the facility is in service during the year divided by 365, and 100 percent for all other years.

(e) The following example illustrates (d) of this section:

Taxpayer A places a facility into service in Year One. The total amount paid to the person building or selling the facility is $1,000,000. The facility comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first partial calendar year of construction, the tax rate is 34 percent and the WACC is five percent. For the second full calendar year of construction, the tax rate is 35 percent and the WACC is six percent. For the third partial calendar year of construction, the tax rate is 37 percent and the WACC is eight percent. For the first year of service the tax rate and WACC are the same as for the third year of construction: the tax rate is 37 percent and the WACC is eight percent. The federal depreciation factors are as follows:

Year 1 = 15%

Year 2 = 22%

Year 3 = 21%

Year 4 = 21%

Year 5 = 21%

Because the facility begins service mid-year, the federal depreciation factors are weighted for time in service as follows:

Year 1 = (0.25 * 15%) = 0.0375

Year 2 = (0.75 * 15%) + (0.25 * 22%) = 0.1675

Year 3 = (0.75 * 22%) + (0.25 * 21%) = 0.2175

Year 4 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 5 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 6 = (0.75 * 21%) = 0.1575

Step One: Calculate the finance factor during construction for the three years of construction under (d)(7) of this section:

For the first calendar year of construction the finance factor during construction would be:

(((1 + 0.05) *exp.* (0.25 * 0.5)) * (1 + 0.06) * ((1 + 0.08) *exp.* (1 - 0.25)) = 1.129854044

For the second calendar year of construction the finance factor during construction would be:

(((1 + 0.06) *exp.* (0.5)) * ((1+0.08) *exp.* (1 - 0.25)) = 1.090738767

For the third calendar year of construction the finance factor during construction would be:

(1 + 0.08) *exp.* (((1 - 0.25) * 0.5) = 1.029280887

Step Two: Calculate the unrecovered investment for the three years of construction under (d)(6) of this section:

For the first year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 0.25 * 1.129854044 = 141,232

For the second year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 1.00 * 1.090738767 = 545,369

For the third year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 0.75 * 1.029280887 = 385,980

Step Three: Calculate the remaining unrecovered investment from the prior year for Year One under (d)(5) of this section:

141,232 + 545,369 + 385,980 = 1,072,581

Step Four: Calculate the discount factor exponent for Year One under (d)(15) of this section:

(((((1 - 0.25) + 1) * 0.5) - 1) + 1) = 0.875

Step Five: Calculate the discount factor for Year One under (d)(14) of this section:

1 / ((1 + 0.08) *exp.* (0.875)) = 0.935

Step Six: Calculate the discounted annual tax depreciation amount for Year One under (d)(12) of this section:

0.0375 * 1,000,000 * 0.37 * 0.935 = 12,971

Step Seven: Calculate the after-tax present value of future tax depreciation benefits for Year One under (d)(11) of this section by adding the discounted tax depreciation amounts for the first five complete years:

Year 1 = 0.0375 * 1,000,000 * 0.37 * 0.935 = 12,971

Year 2 = 0.1675 * 1,000,000 * 0.37 * 0.891 = 55,218

Year 3 = 0.2175 * 1,000,000 * 0.37 * 0.825 = 66,390

Year 4 = 0.2100 * 1,000,000 * 0.37 * 0.764 = 59,352

Year 5 = 0.2100 * 1,000,000 * 0.37 * 0.707 = 54,956

Year 6 = 0.1575 * 1,000,000 * 0.37 * 0.655 = 38,164

Total = 287,051.

Table 1 shows the derivation of the after-tax present value of future tax depreciation benefits for Years One - Six.

Step Eight: Calculate the finance cost for Year One under (d)(4) of this section:

1,072,581 * ((1 + 0.08) *exp.* (0.25 * 0.5)) = 1,082,950

Step Nine: Calculate the present value of an ordinary annuity of 1 for Year One under (d)(16) of this section:

(((1 - (1 / ((1 + 0.08) *exp.* (30))))/0.08) / ((1 + 0.08) *exp.* (-0.5)))/0.25 = 46.79773

Step Ten: Calculate the initial cash flow under (d)(2) of this section:

(1,072,581 - 287,051) / 46.79773 = 16,786

Step Eleven: Calculate the cost of capital allowance under (d)(1) of this section:

16,786 / (1 - 0.37) = 26,644

Step Twelve: Calculate the after-tax cash flow of depreciation benefits for Year One under (d)(9) of this section:

1,000,000 * 0.37 * 0.0375 = 13,875

Step Thirteen: Calculate the total after-tax cash flow for Year One under (d)(8) of this section:

16,786 + 13,875 = 30,661

Step Fourteen: Calculate the remaining unrecovered investment at the end of Year One under (d)(3) of this section:

(1,082,950 - 30,661) * ((1 + .08) *exp.* (0.25 * 0.5)) = 1,062,461

Table 2 shows the capital construction allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1: AFTER-TAX PRESENT VALUE

OF FUTURE DEPRECIATION BENEFITS

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TABLE 2: COST OF CAPITAL ALLOWANCE FOR LNG AND PIPELINE FACILITIES

(continued)

TABLE 2: COST OF CAPITAL ALLOWANCE FOR LNG AND PIPELINE FACILITIES (cont.)

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(f) For a vessel first placed in service on or after January 1, 1995, or for an improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995, a cost of capital allowance that consists of depreciation and a return on investment will be allowed for oil or gas produced during calendar year 2002, except that a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during calendar year 2002. An amount expensed may be either deducted in the month incurred or amortized over all months in calendar year 2002. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated

(A) using the following formula, except as provided in (B) of this paragraph: cost of capital allowance = after-tax cash flow / (1 - marginal federal tax rate); and

(B) for a vessel that was first placed in service on or after January 1, 1995 and before January 1, 2002, or for a capitalized improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, the cost of capital allowance equals after-tax cash flow;

(2) for purposes of (1) of this subsection, after-tax cash flow is calculated using the following formula: after-tax cash flow = remaining unrecovered investment from the prior year / present value of an ordinary annuity of 1 at the end of the remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = ((mid-year unrecovered investment - after-tax cash flow) * ((1 + WACC) *exp.* (portion of year in service * 0.5))) - value of any federal tax credits, deductions, or benefits that are allowable under 26 U.S.C. (Internal Revenue Code), including any tax depreciation deductions and capital construction fund benefit, and that were not included in the calculation made under (6)(A) or (C) of this subsection in the year for which the tax is paid;

(4) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment for the first year the vessel is in service is the net unrecovered capital investment;

(5) for purposes of the formula set out in (3) of this subsection, mid-year unrecovered investment is calculated using the following formula: mid-year unrecovered investment =

remaining unrecovered investment from the prior year * ((1 + WACC) *exp.* (portion of year in service * 0.5));

(6) for purposes of (4) of this subsection, net unrecovered capital investment is the total amount paid to the person building or selling the vessel to the producer, including any improvements to existing vessels,

(A) minus any investment tax credit taken by the producer under 26 U.S.C. 38 (Internal Revenue Code), or in the case of an effectively owned vessel, as described in 15 AAC 55.191(k) , taken by the legal owner of that vessel or facility and passed on in whole or in part to the producer through reduced charter-hire or lease payments; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(B) minus the after-tax net present value of the salvage value of the vessel in Year 25; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(C) minus the net present value in the first year the vessel is in service of any other federal tax credits, deductions, or benefits allowable under 26 U.S.C. (Internal Revenue Code), including any tax depreciation deductions and capital construction fund benefit, where appropriate; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002; and

(D) plus a return on capital used during construction;

(7) for purposes of (6) of this subsection, a return on capital used during construction is the sum of the yearly construction cost of capital for each year of construction, calculated as if the vessel were built over a two-year period before the first month the vessel is first placed in service, with equal amounts paid each year;

(8) for purposes of the formula set out in (7) of this subsection, yearly construction cost of capital for a year is calculated using the following formula: yearly construction cost of capital = construction unrecovered investment - yearly outlay;

(9) for purposes of the formulas set out in (8) and (10) of this subsection, yearly outlay is calculated as if the vessel were built over a two-year period before the first month the is first placed in service, with equal amounts paid each year; yearly outlay is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, and except as provided in (B) of this paragraph, yearly outlay = portion of the year in service for the first calendar year the vessel is in service * 0.5 * total amount paid to the person building or selling the vessel to the producer;

(B) for a vessel that was first placed in service on or after January 1, 1995 and before January 1, 2002, or for a capitalized improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, the yearly outlay is calculated as if the portion of the first calendar year the vessel is in service were zero;

(C) for the second calendar year of construction, yearly outlay = 0.5 * total amount paid to the person building or selling the vessel to the producer;

(D) for the portion of the third calendar year of construction, yearly outlay = (1 - the portion of the year in service for the first calendar year the vessel is in service) * 0.5 * total amount paid to the person building or selling the vessel to the producer;

(10) for purposes of the formula set out in (8) of this subsection, construction unrecovered investment is calculated using the following formula: construction unrecovered investment = yearly outlay * construction finance factor during construction;

(11) for purposes of the formula set out in (10) of this subsection, the construction finance factor during construction is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, the construction finance factor during construction = ((1 + WACC for the first calendar year of construction) *exp.* (portion of the first calendar year the vessel is in service * 0.5)) * (1 + WACC for the second calendar year of construction) * ((1 + WACC for the third calendar year of construction) *exp.* (1 - the portion of the first calendar year the vessel is in service));

(B) for the second calendar year of construction, the construction finance factor during construction = ((1 + WACC for the second calendar year of construction) *exp.* (0.5)) * ((1 + WACC for the third calendar year of construction) *exp.* (1 - the portion of the first calendar year the vessel is in service));

(C) for the portion of the third calendar year of construction, the construction finance factor during construction = (1 + WACC for the third calendar year of construction) *exp.* ((1 - the portion of the first calendar year the vessel is in service) * 0.5);

(12) for purposes of (6) of this subsection, after-tax net present value of the salvage value of the vessel in Year 25 is calculated using the following formula: after-tax net present value of the salvage value of the vessel in Year 25 = 0.04 * total amount paid to the person building or selling the vessel * (1 - marginal federal tax rate for the first year the vessel is in service) * salvage value discount factor;

(13) for purposes of the formula set out in (12) of this subsection, salvage value discount factor is calculated using the following formula: salvage value discount factor = (1 / ((1 + WACC for the first year the vessel is in service) *exp.* (24.5)));

(14) for purposes of the formula set out in (2) of this subsection, present value of an ordinary annuity of 1 at the end of the remaining life is calculated using the following formula: present value of an ordinary annuity of 1 at the end of the remaining life = (((1 - (1 / ((1 + WACC) *exp.* (years of remaining life)))) / WACC) / ((1 + WACC) *exp.* (-0.5))) / portion of year in service;

(15) for purposes of the formula set out in (14) of this subsection, years of remaining life must be determined for a vessel as if the vessel had a 24-year life beginning on the first day of the month that the vessel takes on its first load of oil, and for a capitalized improvement that extends the life of a vessel, as if the capitalized improvement had a 15-year life beginning on the first day of the month that the vessel with the new improvement takes on a load of oil; the life of the vessel or capitalized improvement will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any other reason;

(16) for purposes of the formulas set out in (1) and (12) of this subsection, the marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 35 percent, for a vessel first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(17) for purposes of the formulas set out in (2), (3), (5), (11), (13), and (14) of this subsection, WACC, or the weighted average cost of capital,

(A) except as provided in (B) of this paragraph, is the cost of capital as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, *Standard Industrial Classification Manual,* as revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this paragraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Ibbotson Associates *The Cost of Capital Yearbook* published during the previous calendar year, plus 0.4 percent; and

(B) is eight percent, for a vessel first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(18) for purposes of the formulas set out in (3), (5), (9), and (14) of this subsection, for vessels that are first placed in service by the producer mid-year, the portion of the year in service for the first and last calendar years the vessel is in service is the number of days the vessel is in service during the year divided by 365, and 100 percent for all other years;

(19) vessels first placed in service by the producer on or after January 1, 1995, that were in service for a different producer or for a different person before that date and subject to (a) of this section, continue to be subject to (a) of this section, and the cost of capital allowance set out in this subsection will not be allowed for those vessels; vessels first placed in service by the producer on or after January 1, 1995, that were in service for a different person before that date and subject to (b) of this section, continue to be subject to (b) of this section through December 31, 2001; after December 31, 2001, the cost of capital allowance set out in this subsection will be allowed for those vessels;

(20) for purposes of (6), (9), and (12) of this subsection, if the total amount paid to the person selling the vessel is not based on an arm's-length, third party transaction, is tied to the receipt of other consideration, or cannot reasonably be established by the taxpayer, the total amount paid to the person selling the vessel is the remaining unrecovered investment of the vessel at the time of the acquisition as determined by the department; in making this determination, the department will consider prices paid for similar vessels and other factors related to the value of the vessel;

(21) for purposes of the formula set out in (14) of this section, for vessels first placed in service by the producer on or after January 1, 1995, that either were in service for a different producer or for a different person before January 1, 1995, or were engaged outside the state in ordinary and necessary operations incurred to transport oil or gas before January 1, 1995, years of remaining life must be determined as if the vessel had a total 24-year life and for a capitalized improvement that extends vessel life as if the capitalized improvement had a total 15-year life; the lives of the vessels or capitalized improvements will be considered to have begun at the first loading of oil and will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any reason;

(22) for purposes of (6), (9), and (12) of this subsection, if a vessel is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed; if a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(g) The following example illustrates (f) of this section:

Taxpayer A first places a vessel in service in Year One. The total amount paid to the person building or selling the vessel is $1,000,000. The vessel comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first partial calendar year of construction, the tax rate is 34 percent and the WACC, including the additional 0.4 percent described in (f)(17)(A) of this section, is nine percent. For the second full calendar year of construction, the tax rate is 35 percent and the WACC is eight percent. For the third partial calendar year of construction, the tax rate is 36 percent and the WACC is seven percent. For the first year of service the tax rate and WACC are the same as for the third year of construction. The net present value of the capital construction fund benefit is $354,034.

This example shows the cost of capital allowance for a vessel carrying oil or commingled oil and NGLs.

Step One: Calculate the yearly outlay for each calendar year of construction under (f)(9)(A), (B), and (C) of this section:

For the portion of the first year calendar year of construction the yearly outlay would be:

0.25 * 0.5 * 1,000,000 = 125,000

For the second calendar year of construction the yearly outlay would be:

0.5 * 1,000,000 = 500,000

For the portion of the third calendar year of construction the yearly outlay would be:

(1 - 0.25) * 0.5 * 1,000,000 = 375,000

Step Two: Calculate the construction finance factor during construction for each calendar year of construction under (f)(11) of this section:

For the portion of the first calendar year of construction the construction finance factor during construction would be:

((1 + 0.09) *exp.* (0.25 * 0.5)) * (1 + 0.08) * ((1 + 0.07) *exp.* (1 - 0.25)) = 1.148523540

For the second calendar year of construction the construction finance factor during construction would be:

((1 + 0.08) *exp.* (0.5)) * ((1 + 0.07) *exp.* (1 - 0.25)) = 1.093326088

For the portion of the third calendar year of construction the construction finance factor during construction would be:

(1 + 0.07) *exp.* ((1 - 0.25) * 0.5) = 1.025696602

Step Three: Calculate the construction unrecovered investment for each calendar year of construction under (f)(10) of this section:

For the first calendar year of construction the construction unrecovered investment would be:

125,000 * 1.148523540 = 143,565

For the second calendar year of construction the construction unrecovered investment would be:

500,000 * 1.093326088 = 546,663

For the third calendar year of construction the construction unrecovered investment would be:

375,000 * 1.025696602 = 384,636

Step Four: Calculate the yearly construction cost of capital for each calendar year of construction under (f)(8) of this section:

For the first year of construction the yearly construction cost of capital would be:

143,565 - 125,000 = 18,565

For the second year of construction the yearly construction cost of capital would be:

546,663 - 500,000 = 46,663

For the third year of construction the yearly construction cost of capital would be:

384,636 - 375,000 = 9,636

Step Five: Calculate the return on capital used during construction under (f)(7) of this section:

18,565 + 46,663 + 9,636 = 74,865

Step Six: Calculate the salvage value discount factor under (f)(13) of this section:

(1/ ((1 + 0.07) *exp.* (24.5))) = 0.191

Step Seven: Calculate the after-tax net present value of the salvage value of the vessel in Year 25 under (f)(12) of this section:

0.04 * 1,000,000 * (1 - 0.36) * 0.191 = 4,879

Step Eight: Calculate the net unrecovered capital investment under (f)(6) of this section:

1,000,000 - 354,034 + 74,865 - 4,879 = 715,952

Step Nine: Calculate the present value of an ordinary annuity of 1 at the end of the remaining life under (f)(14) of this section:

(((1 - (1 / ((1 + 0.07) *exp.* (24)))) / 0.07) / ((1 + 0.07) *exp.* (-0.5))) / 0.25 = 47.45589

Step Ten: Calculate the after-tax cash flow under (f)(2) of this section:

715,952 / 47.45589 = 15,087

Step Eleven: Calculate the cost of capital allowance under (f)(1) of this section:

15,087 / (1 - 0.36) = 23,573

Step Twelve: Calculate the mid-year unrecovered investment under (f)(5) of this section:

715,952 * ((1 + 0.07) *exp.* (0.25 * 0.5)) = 722,033

Step Thirteen: Calculate the remaining unrecovered investment under (f)(3) of this section:

(722,033 - 15,087) * ((1 + 0.07) *exp.* (0.25 * 0.5)) 712,951

Table 1 shows the cost of capital allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1

COST OF CAPITAL ALLOWANCE FOR VESSELS CARRYING OIL OR COMMINGLED OIL AND NGLS

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(h) For an improvement to a vessel that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995, a cost of capital allowance that consists of depreciation and a return on investment will be allowed for oil or gas produced during calendar year 2002, except that a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during calendar year 2002. An amount expensed may be either deducted in the month incurred or amortized over all months in calendar year 2002. An improvement that the producer treats as an expense under 26 U.S.C. 179 may not receive a cost of capital allowance under this subsection. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated using the following formula: cost of capital allowance = initial cash flow / (1 - marginal federal tax rate);

(2) for purposes of the formula set out in (1) of this subsection, initial cash flow is calculated using the following formula: initial cash flow = (remaining unrecovered investment from the prior year - after-tax present value of future tax depreciation benefits) / present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = (finance cost - total after-tax cash flow) * ((1 + WACC) ***exp.*** **(portion of year in service * 0.5));**

(4) for purposes of the formula set out in (3) of this subsection, finance cost is calculated using the following formula: finance cost = remaining unrecovered investment from the prior year * ((1 + WACC) ***exp.*** **(portion of year in service * 0.5));**

(5) for purposes of the formula set out in (4) of this subsection, remaining unrecovered investment from the prior year for the first year the capitalized improvement to a vessel is in service is the total amount paid to the person building or selling the capitalized improvement to the producer;

(6) for purposes of the formula set out in (3) of this subsection, total after-tax cash flow is calculated using the following formula: total after-tax cash flow = initial cash flow + after-tax cash flow of depreciation benefits for that tax year;

(7) for purposes of the formula set out in (6) of this subsection, after-tax cash flow of depreciation benefits for that tax year is calculated using the following formula: after-tax cash flow of depreciation benefits for that tax year = total amount paid to the person building or selling the capitalized improvement to a vessel to the producer * marginal federal tax rate * federal depreciation factor;

(8) for purposes of the formulas set out in (7) and (11) of this subsection, the federal depreciation factor

(A) except as provided in (B) of this paragraph, is the percentage of the total amount paid to the person building or selling the capitalized improvement by the producer that can be depreciated for federal corporate income tax for the tax year; and

(B) for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, is the percentage allowed on a five-year schedule as follows:

(i) for year one, 15 percent;

(ii) for year two, 22 percent;

(iii) for year three, 21 percent;

(iv) for year four, 21 percent;

(v) for year five, 21 percent;

(9) for purposes of (2) of this subsection, after-tax present value of future tax depreciation benefits is the sum of the discounted annual tax depreciation amounts for each remaining year in which the total amount paid to the person building or selling the pipeline facility to the producer can be depreciated for federal corporate income tax for the tax year;

(10) for purposes of (9) of this subsection, a discounted annual tax depreciation amount is calculated using the following formula: discounted annual tax depreciation amount = federal depreciation factor * total amount paid to the person building or selling the capitalized improvement to a vessel to the producer * marginal federal tax rate * discount factor;

(11) for purposes of the formulas set out in (1), (7), and (10) of this subsection, marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 37 percent, for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(12) for purposes of the formula set out in (10) of this subsection, discount factor is calculated using the following formula: discount factor = 1 / ((1 + WACC) ***exp.*** **(discount factor exponent));**

(13) for purposes of the formula set out in (12) of this subsection, the discount factor exponent is calculated using the following formula: discount factor exponent = (((((1 - portion of year in service) + 1) * 0.5) - 1) + year depreciation benefit is realized);

(14) for purposes of the formula set out in (2) of this subsection, the present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC, is calculated using the following formula: present value of an ordinary annuity of 1 at the end of n periods = (((1 - (1/ ((1 + WACC) ***exp.*** **(years of remaining life)))) / WACC) / ((1 + WACC)** ***exp.*** **(-0.5))) / portion of year in service;**

(15) for purposes of the formula set out in (14) of this subsection, years of remaining life must be determined for each capitalized improvement to a vessel as if it had a 10-year life beginning on the first day of the month that the vessel with the new improvement takes on a load of oil; the life of the capitalized improvement will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any other reason;

(16) for purposes of the formulas set out in (2), (3), (4), (12), and (14) of this subsection, WACC, or the weighted average cost of capital,

(A) except as provided in (B) of this paragraph, is the cost of capital as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, ***Standard Industrial Classification Manual,*** **as**

revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this paragraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Ibbotson Associates *The Cost of Capital Yearbook* published during the previous calendar year, plus 0.4 percent; and

(B) is eight percent, for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(17) for purposes of the formula set out in (3), (4), (13), and (14) of this subsection, for capitalized improvements to a vessel that come into service mid-year, the portion of the year in service for the first and last calendar years the capitalized improvement to a vessel is in service is the number of days the capitalized improvement to a vessel is in service during the year divided by 365, and 100 percent for all other years;

(18) capitalized improvements to a vessel acquired for service on or after January 1, 1995, that were in service before that date and subject to (a) of this section, continue to be subject to (a) of this section, and the cost of capital allowance set out in this subsection will not be allowed for those capitalized improvements; capitalized improvements to a vessel acquired for service on or after January 1, 1995, that were in service before that date and subject to (b) of this section continue to be subject to (b) of this section through December 31, 2001; after December 31, 2001, the cost of capital allowance set out in this subsection will be allowed for those capitalized improvements;

(19) for purposes of (5), (7), and (10) of this subsection, if the total amount paid to the person selling the capitalized improvement to a vessel is not based on an arm's-length, third party transaction, is tied to the receipt of other consideration, or cannot reasonably be established by the taxpayer, the total amount paid to the person selling the capitalized improvement to a vessel will be determined by the department; in making this determination, the department will consider prices paid for similar improvements and other factors related to the value of the capitalized improvement;

(20) for purposes of (5), (7), and (10) of this subsection, if a capitalized improvement to a vessel is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed; if a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(i) The following example illustrates (h) of this section:

Taxpayer A places a capitalized improvement to a vessel into service in Year One. The total amount paid to the person building or selling the improvement is $1,000,000. The improvement comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first year of service the tax rate is 37 percent and the WACC, including the additional 0.4 percent described in (h)(16) of this section, is six percent. The federal depreciation factors are as follows:

Year 1 = 15%

Year 2 = 22%

Year 3 = 21%

Year 4 = 21%

Year 5 = 21%

Because the improvement begins service mid-year, the federal depreciation factors are weighted for time in service as follows:

Year 1 = (0.25 * 15%) = 0.0375

Year 2 = (0.75 * 15%) + (0.25 * 22%) = 0.1675

Year 3 = (0.75 * 22%) + (0.25 * 21%) = 0.2175

Year 4 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 5 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 6 = (0.75 * 21%) = 0.1575

This example shows the cost of capital allowance for an improvement to a vessel carrying oil or commingled oil and NGLs.

Step One: Calculate the discount factor exponent for Year One under (h)(13) of this section:

(((((1 - 0.25) + 1) * 0.5) - 1) + 1) = 0.875

Step Two: Calculate the discount factor for Year One under (h)(12) of this section:

1 / ((1 + 0.06) *exp.* (0.875)) = 0.950

Step Three: Calculate the discounted annual tax depreciation amount for Year One under (h)(10) of this section:

0.0375 * 1,000,000 * 0.37 * 0.950 = 13,185

Step Four: Calculate the after-tax present value of future tax depreciation benefits for Year One under (h)(9) of this section by adding the discounted tax depreciation amounts for the first five complete years:

Year 1 = 0.0375 * 1,000,000 * 0.37 * 0.950 = 13,185

Year 2 = 0.1675 * 1,000,000 * 0.37 * 0.916 = 56,788

Year 3 = 0.2175 * 1,000,000 * 0.37 * 0.864 = 69,566

Year 4 = 0.2100 * 1,000,000 * 0.37 * 0.816 = 63,365

Year 5 = 0.2100 * 1,000,000 * 0.37 * 0.769 = 59,788

Year 6 = 0.1575 * 1,000,000 * 0.37 * 0.726 = 42,296

Total 304,979.

Table 1 shows the derivation of the after-tax present value of future tax depreciation benefits for Years One - Six.

Step Five: Calculate the finance cost for Year One under (h)(4) of this section:

1,000,000 * ((1 + 0.06) _exp._ (0.25 * 0.5)) = 1,007,310

Step Six: Calculate the present value of an ordinary annuity of 1 for Year One under (h)(14) of this section:

(((1 - (1 / ((1 + 0.06) _exp._ (10)))) / 0.06) / ((1 + 0.06) _exp._ (-0.5)))/ 0.25 = 30.31069

Step Seven: Calculate the initial cash flow under (h)(2) of this section:

(1,000,000 - 304,979)/ 30.31069 = 22,930

Step Eight: Calculate the cost of capital allowance under (h)(1) of this section:

22,930 / (1 - 0.37) = 36,397

Step Nine: Calculate the after-tax cash flow of depreciation benefits for Year One under (h)(7) of this section:

1,000,000 * 0.37 * 0.0375 = 13,875

Step Ten: Calculate the total after-tax cash flow for Year One under (h)(6) of this section:

22,930 + 13,875 = 36,805

Step Eleven: Calculate the remaining unrecovered investment at the end of Year One under (h)(3) of this section:

(1,007,310 - 36,805) * ((1 + .06) _exp._ (0.25 * 0.5)) = 977,600

Table 2 shows the capital construction allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1: AFTER-TAX PRESENT VALUE OF FUTURE DEPRECIATION BENEFITS

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TABLE 2: COST OF CAPITAL ALLOWANCE FOR IMPROVEMENTS TO VESSELS CARRYING OIL OR COMMINGLED OIL AND NGLS

TABLE 2: COST OF CAPITAL ALLOWANCE FOR IMPROVEMENTS TO VESSELS CARRYING OIL OR COMMINGLED OIL AND NGLS (cont.)

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History: Eff. 1/1/2000; Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

Editor's note: The material adopted by reference in 15 AAC 55.195(d) , (f), and (h) from the *Standard Industrial Classification Manual* may be viewed at or obtained from the Department of Revenue, Tax Division, 550 W. 7th Avenue, Suite 500, Anchorage, AK 99501. *The Cost of Capital Yearbook* is published by Ibbotson Associates, 225 North Michigan Avenue, Suite 700, Chicago, Illinois 60601.

Before 1/1/2000, Register 152, the substance of 15 AAC 55.195(a) , (b), and (c) was in 15 AAC 55.191(d) , (f), and (g). The history note for 15 AAC 55.195 does not reflect the earlier history of the provisions currently set out at 15 AAC 55.195(a) , (b), and (c).

15 AAC 55.196. Cost of capital allowance to be used in calculation of reasonable costs of vessel transportation for oil or gas produced on or after January 1, 2003, other than certain costs pertaining to vessels placed in service before January 1, 1995

(a) Except if 15 AAC 55.195(a) applies, for oil or gas produced on or after January 1, 2003, a cost of capital allowance that consists of depreciation and a return on invested capital will be allowed under this section for a vessel, or an improvement completed on or after January 1, 2002 to a vessel, owned or effectively owned by the producer, as provided in 15 AAC 55.191. However, a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during a calendar year.

(b) A cost of capital allowance under this section will be allowed only for days when the vessel is in allowable service, in allowable lay up, or in allowable dry dock.

(c) The following requirements apply to the timing of changes in vessel status:

(1) a vessel changing from operation in allowable service to lay up or operation in alterative service begins lay up or operation in alternative service on the day after the last day of cargo discharge in allowable service;

(2) a vessel changing from operation in alternative service to lay up or operation in allowable service begins lay up or operation in allowable service on the day after the last day of cargo discharge in alternative service;

(3) a vessel changing from lay up to operation in allowable service or operation in alternative service begins operation in allowable service or operation in alternative service on the day after the vessel departs from the location where the vessel was laid up;

(4) a vessel going into dry dock begins dry dock status on the day after the last day of cargo discharge or, if going into dry dock from lay up, on the day after the vessel departs from the location where the vessel was laid up;

(5) a vessel finishing dry dock changes from dry dock status to the immediately subsequent status on the day after the vessel departs the dry dock facility;

(6) a vessel begins operation in allowable service on the day that its useful life begins or, in the case of a used vessel newly acquired by a producer, on the day that its remaining useful life for that producer begins, if the vessel proceeds directly to enter operation in allowable service; otherwise, the vessel begins operation in alternative service on the day specified in this paragraph; for purposes of this paragraph, the beginning of a vessel's useful life or remaining useful life is determined in accordance with generally accepted accounting principles.

(d) A cost of capital allowance under this section must be calculated using the methodology set out in the department's publication *Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements,* Second Edition, dated September 19, 2003 and adopted by reference.

(e) For purposes of this section,

(1) a vessel is in allowable service if the vessel is

(A) in service within the meaning given in 15 AAC 55.900, except when the vessel is in dry dock; or

(B) idle for a period of fewer than 90 consecutive days immediately before operation in allowable service under (A) of this paragraph; for purposes of this subparagraph, a vessel is not idle if it is in dry dock;

(2) a vessel is laid up if it is idle for a period of 90 or more consecutive days; for purposes of this paragraph, a vessel is not idle if it is in dry dock;

(3) a vessel is in allowable lay up if the vessel is laid up during a calendar year, but only to the extent that the total number of days it is or has been laid up while owned or effectively owned by the producer through the end of that calendar year does not exceed the total number of days it is or has been in allowable service while owned or effectively owned by the producer through the end of that calendar year;

(4) a vessel is in allowable dry dock if the vessel is in dry dock during a calendar year, but only for that fraction of the total days in dry dock that equals the sum of the number of days during the year that the vessel is in allowable service and the number of days during the year that the vessel is in allowable lay up, divided by the sum of the number of days during the year that the vessel is in allowable service, the number of days during the year that the vessel is laid up, and the number of days during the year that the vessel is in alternative service;

(5) a vessel is in alternative service if it is not in lay up, dry dock, or allowable service; and

(6) if necessary to determine a vessel's status during a month, the vessel's status at later times will be considered.

History: Eff. 1/1/2003, Register 164; am 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

Editor's note: Copies of *Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements,* adopted by reference in 15 AAC 55.196(d) , may be obtained from the Tax Division, Department of Revenue, 550 W. Seventh Ave., Suite 500, Anchorage, Alaska 99501-3566.

15 AAC 55.200. Retroactive adjustments

If retroactive adjustments in costs of transportation, sales price, prevailing value, or consideration for quality differentials relating to the commingling of oils or of oil and NGLs result from decisions of regulatory agencies, courts, or any other preemptive authority, those adjustments have a corresponding effect, either an increase or decrease as applicable, on the gross value at point of production as determined under this chapter, and the producer shall, on or before the third monthly payment due date specified in AS 43.55.020 (a) after any adjustment, file amended returns covering the entire period of an adjustment unless the producer has obtained a stay on that filing or payment, regardless of the pendency of appeals of those decisions.

History: Eff. 1/6/80, Register 73; am 1/1/2000, Register 152

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

15 AAC 55.210. Definitions

Repealed.

History: Eff. 1/6/80, Register 73; repealed 1/1/95, Register 132

15 AAC 55.220. Oil and gas exploration tax credit

(a) An explorer may request an oil and gas exploration tax credit by filing an application with the department no later than six months after the completion date of the exploration activity for which the tax credit is claimed.

(b) For a particular exploration well, an explorer may claim a tax credit of

(1) 20 percent of exploration expenditures,

(A) if those expenditures qualify under AS 43.55.025 (b) and (c); and

(B) regardless of whether the well is less than 25 miles from an existing unit that is under a plan of development;

(2) 20 percent of exploration expenditures,

(A) if those expenditures qualify under AS 43.55.025 (b) and (d); and

(B) regardless of whether the bottom hole of the exploration well is less than three miles away from the bottom hole of a preexisting suspended, completed, or abandoned oil or gas well; or

(3) 40 percent of exploration expenditures, if those expenditures qualify under AS 43.55.025 (b), (c), and (d).

(c) For a particular seismic or geophysical exploration activity, an explorer may claim a tax credit of 40 percent of exploration expenditures, if those expenditures qualify under AS 43.25.025 (b) and (e).

History: Eff. 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.225. Oil and gas exploration tax credit claim

(a) An application for an exploration tax credit for a particular exploration activity may, on a form provided by the department, be filed by

(1) a single explorer that

(A) holds the entire interest in the particular well or seismic or geophysical exploration activity; and

(B) incurred 100 percent of the expenditures for which the credit is claimed; or

(2) a designated joint applicant that is authorized in a writing, signed by each explorer that incurred expenditures, to file a joint tax credit application on behalf of all those explorers; a joint application must be for the total qualified expenditures incurred by all the explorers for the exploration activity for which the credit is claimed and must include a copy of the written authorization signed by each explorer.

(b) A tax credit application for an exploration well must include the following information:

(1) the applicant's name, permanent contact address, and telephone number;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date the exploration well was spudded, the date it was drilled, and the completion date;

(6) the bottom hole location and the surface location of the exploration well;

(7) for an application under AS 43.55.025 (b) and (c), the

(A) bottom hole location of the nearest preexisting well,

(B) date the nearest preexisting well was drilled,

(C) completion date of the nearest preexisting well; and

(D) the distance between the bottom hole location of the exploration well and the bottom hole location of the nearest preexisting well, measured as a horizontal distance between the surface location directly above the bottom hole location of each well;

(8) if the exploration well is within a unit boundary,

(A) identification of the unit; and

(B) a copy of the plan of exploration or plan of development that was in effect for the unit on May 13, 2003;

(9) for an application under AS 43.55.025 (b) and (d),

(A) identification of the nearest unit that is under a plan of development; and

(B) the distance between the bottom hole location of the exploration well and the outer boundary of the nearest unit that is under a plan of development,

(i) as the boundary was delineated on July 1, 2003; and

(ii) measured as a horizontal distance between the surface location directly above the bottom hole location of the well and the nearest point on the outer boundary of the unit;

(10) a survey plat that graphically identifies all the locations, distances, and dates required under this subsection;

(11) a copy of the Well Completion or Recompletion Report and Log (Form 10-407) for the exploration well filed with the Alaska Oil and Gas Conservation Commission under 20 AAC 25.070 and, if the application is for expenditures that qualify under AS 43.55.025 (c)(2), a copy of the Well Completion or Recompletion Report and Log for the nearest preexisting well;

(12) the written agreements required under AS 43.55.025 (f)(2);

(13) other information requested by the department, as the department considers necessary for reviewing the application.

(c) A tax credit application for a particular seismic or geophysical exploration activity must include the following information:

(1) the name, permanent contact address, and telephone number of the applicant;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the seismic or geophysical exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date of and location where the seismic or geophysical activity occurred;

(6) a statement verifying

(A) that the seismic or geophysical exploration activities occurred outside of the boundaries of a unit that is under a plan of exploration or a plan of development; or

(B) the percentage of the seismic or geophysical exploration activities that occurred inside the unit boundary, if a portion of those activities crossed into the boundary of a unit;

(7) the written agreements required under AS 43.55.025 (f)(2);

(8) other information requested by the department, as the department considers necessary for reviewing the application.

(d) An applicant under this section shall retain, and make available to the department upon request, all financial and technical source documents and records supporting the credit claimed for an exploration well or seismic or geophysical exploration activities, including the rig logs, daily drilling logs, and activity logs.

(e) After the six-month application period in AS 43.55.025 (f) has expired, the department will issue one or more production tax credit certificates for the qualified expenditures allowed under AS 43.55.025 .

(f) The department may allocate claimed expenditures between exploration and non-exploration activities, and will deny a claimed exploration expenditure that it determines not to be reasonably required or not incurred for qualified exploration activities.

History: Eff. 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.230. Qualified exploration expenditures

(a) For purposes of the oil and gas exploration tax credit, qualified exploration expenditures are the reasonably required direct costs for work performed on a particular exploration well or seismic or geophysical exploration project on or after July 1, 2003 and before July 1, 2007.

(b) Qualified exploration expenditures for an exploration well include costs incurred for

(1) surveying and preparing the exploration well drill site;

(2) constructing new ice or gravel roads, from the terminus of an existing ice or gravel road used in oil or gas operations to the exploration well site, and building and maintaining docks, helipads, or landing areas necessary to the exploratory drilling activity; costs for these activities are calculated as follows:

(A) for a road, dock, helipad, or landing area, the cost is the actual cost incurred;

(B) if the road, dock, helipad, or landing area is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, that it is used for each activity, divided by the total number of hours or days it is used for all activities;

(3) in-state travel, temporary living quarters, and subsistence at or near the exploration well site for drilling crew and personnel engaged in onsite exploration activities;

(4) drilling rig costs, including

(A) transportation and preparation, including the costs of moving the drilling rig to the exploration well site, mobilization, rigging-up, de-mobilization, and rigging-down of the drilling rig on the exploration well site;

(B) onsite costs for operating the drilling rig, including onsite coring and well logging; onsite drilling rig operating costs are calculated as follows:

(i) if the drilling rig is under a third-party contract, the costs are calculated at the contractual operating rate;

(ii) if the drilling rig is owned wholly or partly by an explorer, the costs are calculated on the basis of the net book value of the rig on the date it arrives on the exploration well site; if the exploration well drilling activities are the first use of a drilling rig after it is transported into the state, the cost of transporting the drilling rig to the state and to the area-wide dock is added to the net book value of the drilling rig;

(iii) drilling rig operating costs may be claimed from the date the drilling rig arrives on the exploration well site until the earliest of the completion date, the date the drilling rig is released from the drilling operation, or the date the drilling rig moves off the exploration well site; if drilling activities are suspended for any reason for 15 consecutive calendar days, drilling rig operating costs are not allowed under this subparagraph for those 15 days or for any subsequent day until drilling activities are resumed; and

(C) drilling materials, supplies, maintenance, repairs, drilling crew labor, and drilling waste handling;

(5) transportation equipment used for drilling crews; the cost of transportation equipment is calculated as follows:

(A) if the equipment is under a third-party contract, the cost is calculated at the hourly or daily contract rate, as appropriate, multiplied by the number of hours or days the equipment is actually used for the exploration activity for which the credit is claimed, divided by the number of hours or days the equipment was available by contract for use in the exploration activity;

(B) if the equipment is owned wholly or partly by an explorer, the cost is calculated on the basis of the net book value of the equipment multiplied by the number of days or hours, as appropriate, the equipment is used in the exploration activity for which the credit is claimed, divided by the number of days or hours of estimated remaining useful life of the equipment;

(C) if the equipment is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities; and

(6) communications expenses necessary to the exploration well.

(c) Qualified exploration expenditures for seismic and geophysical exploration include costs incurred for

(1) seismic exploration activities, initial processing of data derived from seismic exploration activities, and downhole geophysical surveys associated with well logging;

(2) in-state travel, temporary living quarters, and subsistence at or near the exploration site for seismic crew and other personnel engaged in the exploration activities;

(3) the seismic exploration crew; seismic exploration crew costs are calculated as follows:

(A) if the crew is provided under a third-party contract, at the rate provided in the contract;

(B) if the crew is provided by an explorer, as actual payments to the crew for time expended on the seismic activity;

(4) goods, services, and materials; costs for goods, services, and materials are calculated as follows:

(A) if goods, services, and materials are provided under a third-party contract, the costs are calculated at the contract rate;

(B) if goods, services, and materials are provided in whole or in part by an explorer, the costs are the actual costs incurred;

(C) if a good, service or material is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities; and

(5) seismic and geophysical equipment, off-site computers, and other modeling equipment used in the initial seismic data processing; the cost of that equipment, including maintenance and repairs, is calculated as follows:

(A) if the equipment is under a third-party contract, the cost is calculated at the hourly or daily contract rate multiplied by the number of hours or days, as appropriate, that the equipment is actually used for the exploration activity for which the credit is claimed, divided by the number of hours or days the equipment was available by contract for use in the exploration activity;

(B) if the equipment is owned wholly or partly by an explorer, the cost is calculated on the basis of the net book value of the equipment multiplied by the number of days or hours, as appropriate, the equipment is used in the exploration activity for which the credit is claimed, divided by the number of days or hours of estimated remaining useful life of the equipment;

(C) if the equipment is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities.

(d) Qualified exploration expenditures do not include costs that are disallowed under AS 43.55.025 (b)(3) or (b)(4). For purposes of AS 43.55.025 (b)(3) and this subsection,

(1) "testing, stimulation, or completion costs" means costs incurred on the exploration site after discovery of oil or gas potential at the site, including costs incurred to prepare an exploration well for, or convert it to production, to prepare or monitor an exploration well for status as a producer or potential producer, or to conduct flow tests; in this paragraph, "discovery of oil or gas potential" means drilling an exploration well into a formation capable of producing previously undiscovered oil or gas reserves;

(2) "administration, supervision, engineering, or lease operating costs" means overhead costs incurred for activities that

(A) do not occur on the exploration site; and

(B) are not directly related to drilling an exploration well or conducting seismic exploration, including geophysical surveys other than seismic surveys;

(3) "geological or management costs" means costs incurred before drilling begins to determine or select possible exploration targets; "geological or management costs" includes airborne gravity and magnetic surveys;

(4) "community relations or environmental costs" includes costs incurred for environmental compliance programs required as a result of an environmental incident, spill, or

(5) "indirect or financing costs" includes

(A) bottom hole and dry hole contributions, and reimbursements and fees assessed for late participation; and

(B) seismic or geophysical data purchased from another person.

(e) in this section,

(1) "labor costs" means the actual costs of labor, including the amount of customary or required benefits;

(2) "net book value" means, under generally accepted accounting principles, the dollar amount the owner of an asset records in its financial statement as the historical cost of the asset, excluding capitalized interest and net of accumulated depreciation or amortization.

History: Eff. 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.235. Transfer of a production tax credit certificate

(a) A person may transfer an interest in a production tax credit certificate by notifying the department, on a transfer form provided by the department. A transfer form must include the following information:

(1) the name, federal tax identification number, and address of the transferor and the transferee;

(2) the amount of tax credit that was transferred, the nature of the transfer, and the monetary or other value received.

(b) Transfer of a production tax credit certificate is effective on the date the department sends notice to the transferor that the certificate has been transferred.

(c) After a person has notified the department of a transfer under (a) of this section, the person may not use or transfer any additional interest in the production tax credit certificate until the effective date of the transfer under (b) of this section.

(d) In this section, "transfer" means to sell, assign, exchange, or convey in any manner an interest in a production tax credit certificate, regardless of whether compensation is received.

History: Eff. 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.240. Applying production tas credit certificates against production tax liability

(a) A producer may apply a production tax credit certificate only against its monthly production tax liability under this chapter, and not against a penalty or interest on production taxes.

(b) To apply a production tax credit certificate to a production tax liability, a producer must submit to the department, with the monthly production tax statement required under AS 43.55.030 , a written designation, on a form provided by the department, stating the amount of tax credit to be applied against the tax liability and each tax period against which it is to be applied.

(c) On receipt of a written designation under (b) of this section, the department will apply the designated tax credit against the producer's production tax liability for the designated tax period before any other credits authorized by AS 43.55 are applied against the same tax liability for the same tax period, and if the producer's total production tax liability in the designated tax period is

(1) greater than the designated tax credit, the producer shall pay the balance of the production tax liability in the manner provided in this chapter; or

(2) less than the designated tax credit, the excess amount of a production tax credit designated for that tax period will be applied as a credit against the next tax period for which the producer has an unpaid tax liability.

(d) A production tax credit certificate does not accrue interest, and except for application against the production tax liability as provided in this chapter, may not be used in payment of any tax or other amount owed.

History: Eff. 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.900. Definitions

(a) Unless the context otherwise requires, as used in this chapter

(1) "department" means the Department of Revenue;

(2) "FASB" means the Financial Accounting Standards Board;

(3) "FASB-13" means FASB's Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (November 1976), as amended or interpreted by FASB's Statement of Financial Accounting Standards No. 17, "Accounting for Leases - Initial Direct Costs" (November 1977); FASB's Statement of Financial Accounting Standards No. 22, "Changes in the Provisions of Lease Agreements Resulting from Refundings of Tax-Exempt Debt" (June 1978); FASB's Statement of Financial Accounting Standards No. 23, "Inception of the Lease" (August 1978); FASB Interpretation No. 19, "Lessee Guarantee of the Residual Value of Leased Property" (October 1977); and FASB Interpretation No. 21, "Accounting for Leases in a Business Combination" (April 1978);

(4) "LNG transportation facility" means any or all of the following: the LNG liquefaction plant, gathering lines to that plant, loading and unloading facilities for LNG tankers, or LNG tankers;

(5) "pipeline facility" means all facilities incident to the pipeline transportation of oil or gas downstream from the point of production;

(6) "point of production" means

(A) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; in the absence of an automatic custody transfer meter or unit, "point of production" for oil means the outlet flange of the tank gauge, or in the absence of a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose, through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;

(B) for gas recovered from or in association with oil, the first point after the gas has been completely separated from oil, including condensate and distillate, and where the gas is accurately metered or measured; for purposes of this paragraph, gas and oil have not been completely separated if hydrocarbon liquids extracted by gas processing are blended with oil upstream of the final stage of separation of gas from oil;

(C) for gas not recovered from or in association with oil, the first point after the gas has been completely separated from condensate and distillate where the gas is accurately metered or measured;

(7) "sales delivery point" means

(A) for a producer's oil or gas sold in a bona fide, arm's-length sale to a third party, the point of delivery specified under the terms of the contract or agreement for that sale, except as otherwise provided by 15 AAC 55.151(g) , or 15 AAC 55.191(i) ;

(B) for a producer's oil or oil and commingled NGLs to which (A) of this paragraph does not apply, the point where prevailing value is calculated under 15 AAC 55.171; and

(C) for a producer's gas other than NGLs commingled with oil to which (A) of this paragraph does not apply, the point where prevailing value is calculated under 15 AAC 55.173;

(8) "same market" means

(A) with respect to an oil that a producer refines or ultimately disposes of in the state, the Alaskan market;

(B) with respect to a producer's oil delivered to the United States West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii);

(C) with respect to a producer's oil delivered to the United States Gulf Coast, the Gulf Coast market;

(D) with respect to a producer's oil delivered to the United States East Coast, the East Coast market;

(E) with respect to a producer's oil delivered to Puerto Rico or the United States Virgin Islands, the Puerto Rico and United States Virgin Islands market;

(F) with respect to a producer's oil delivered to the United States Midcontinent region, the Midcontinent market;

(G) with respect to a producer's gas marketed in the state, the Alaskan market or portion of it served by gas from the same field or area as the producer's gas;

(H) with respect to a producer's gas marketed in the Lower 48, the Lower 48 market;

(I) with respect to a producer's oil or gas marketed in a foreign country, the market in that foreign country.

(9) "ANS" means oil, or commingled oil and NGLs, produced in the Alaska North Slope area;

(10) "crude" means oil or unrefined liquid petroleum consisting principally of oil;

(11) "exchange"

(A) means a disposition of oil, or of commingled oil and NGLs, by a producer to a third party in which all or a portion of the full consideration received is oil or other non-cash consideration; and

(B) includes a related buy-sell agreement, tied sale, ratio exchange, or other arrangement where the producer's disposition of the oil, or of commingled oil and NGLs, to a third party is conditioned on the producer's purchase or receipt of oil or other non-cash consideration from that third party;

(12) "GNP deflator" means the gross national product deflator, as calculated quarterly by the Bureau of Economic Analysis, Economics and Statistics Administration, United States Department of Commerce;

(13) "LNG" means liquified natural gas;

(14) "NGLs" means hydrocarbon liquids extracted from gas at a gas processing plant;

(15) "quality bank differential" means the difference per barrel between the value of a specified ANS stream that is commingled with one or more other streams at a pipeline connection and the value of the commingled pipeline stream, sometimes known as the reference stream, immediately downstream from that pipeline connection, as that difference in value is calculated by the person administering the pipeline quality bank for that pipeline connection;

(16) "residue gas" means the gas remaining after NGLs have been extracted by gas processing at a gas processing plant; "residue gas" includes gas used as fuel and gas that is reinjected into the reservoir;

(17) "TAPS" means Trans Alaska Pipeline System;

(18) "consolidated business" means a corporation or group of corporations having more than 50 percent common ownership, direct or indirect, or a group of corporations in which common control exists, either direct or indirect, as evidenced by an arrangement, contract, or agreement;

(19) "in service" means

(A) engaged in transporting oil or gas produced in the state;

(B) returning to the state from a voyage that transported oil or gas produced in the state; or

(C) engaged in the ordinary and necessary operations incurred to transport oil or gas produced in the state;

(20) "field topping plant" means a facility into which a portion of a stream of hydrocarbon liquids is diverted and run, where distillation techniques are used to separate and remove certain liquid hydrocarbon fractions from the diverted liquids, and from which the remaining fractions of those hydrocarbon liquids are returned and blended back into the stream of undiverted hydrocarbon liquids at a point upstream of the point that constitutes the point of production for the undiverted liquids.

(b) Unless the context otherwise requires, as used in this chapter and in AS 43.55,

(1) "area" means a geographic region or geologic province, including the Cook Inlet basin or the North Slope of the state;

(2) "field" means that part of an area underlain by one or more overlapping, contiguous, or superimposed pools, including Prudhoe Bay field or Middle Ground Shoal field in the state;

(3) "producer" means an owner of an operating right, operating interest, or working interest in a mineral interest in oil or gas; for purposes of this paragraph, an owner includes a proprietorship, a partnership, a joint venture, a limited liability company, a corporation, or all members of a group of any such entities in which one exercises significant influence over the others within the meaning of Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock," paragraph 17 (March 1971).

(4) "condensate" means liquid hydrocarbons

(A) that can reasonably be separated from gas without the use of gas processing, regardless of whether

(i) the gas was produced from a gas reservoir or an oil reservoir; or

(ii) the liquid hydrocarbons existed in a gaseous or liquid phase in the reservoir; or

(B) recovered from gas other than at a gas processing plant;

(5) "distillate" is condensate;

(6) "gas processing"

(A) means the extraction of hydrocarbon and non-hydrocarbon elements or compounds from gas by absorption, adsorption, or refrigeration; for purposes of this subparagraph, "refrigeration" means

(i) externally applied refrigeration; or

(ii) auto-refrigeration by external compression and adiabatic expansion of gas through a Joule-Thomson valve or similar device;

(B) does not include reduction of natural pressure, mechanical separation, condensate stabilization, alteration of pressure or temperature in a reservoir, or processes such as heating, cooling, dehydration, and compression necessary for safe and efficient field operations;

(7) "gas processing plant" means a facility, downstream of the point of production for gas, that extracts hydrocarbon compounds from gas by gas processing; a facility may be a gas processing plant with respect to certain of its products even if it is not a gas processing plant with respect to other products.

(8) "abandoned" has the meaning given in 20 AAC 25.990;

(9) "bottom hole" has the meaning given the term "bottom-hole location" in 20 AAC 25.990;

(10) "completion date" means, for

(A) an exploration well, the earliest of the dates drilling ceased on the well site, the well was abandoned, or the well was suspended; and

(B) a preexisting well, the date the well was completed and equipped for producing fluids;

(11) "exploration unit" means a unit that is under a plan of exploration;

(12) "exploration well" means a well drilled to discover or to delineate a pool or to gain structural or stratigraphic information to aid in exploring for oil and gas;

(13) "explorer" has the meaning given in AS 43.55.025 ; "explorer" does not include a drilling contractor, operator, or other person that does not hold an interest in the exploration well or seismic or geophysical work;

(14) "plan of exploration" means a plan submitted in accordance with 11 AAC 83.341;

(15) "plan of development" means a plan submitted in accordance with 11 AAC 83.343;

(16) "production unit" means a unit that is under a plan of development;

(17) "new oil or gas reserves" means previously undiscovered oil or gas reserves;

(18) "reserves" means unproduced but recoverable oil or gas in place in a formation;

(19) "suspended" has the meaning given in 20 AAC 25.990;

(20) "unit" means a unit approved by the commissioner of natural resources under AS 38.05.180 .

(c) As used in AS 43.55, "agreement for unitization or pooling" means an agreement under which two or more persons owning working interests in a mineral interest in oil or gas or both agree to have the interests operated on a unified basis and further agree to share in production on a stipulated percentage or fractional basis regardless of the interest or interests from which the oil or gas is actually recovered and produced.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.025

AS 43.55.110

AS 43.55.150

AS 43.55.900

Editor's note: Definitions for this chapter were formerly in 15 AAC 55.210.

15 AAC 55.9660. Number of oil wells

Repealed 7/1/77.

15 AAC 55.9670. Daily per well oil production

Repealed 7/1/77.

15 AAC 55.9690. Sales production ratio

Repealed 3/7/74.

15 AAC 55.9694. Tax rate changes based on wholesale price index

Repealed 7/1/77.

15 AAC 55.9699. Point of valuation of oil

Repealed 1/6/80.

15 AAC 55.9700. Definitions

Repealed 1/6/80.